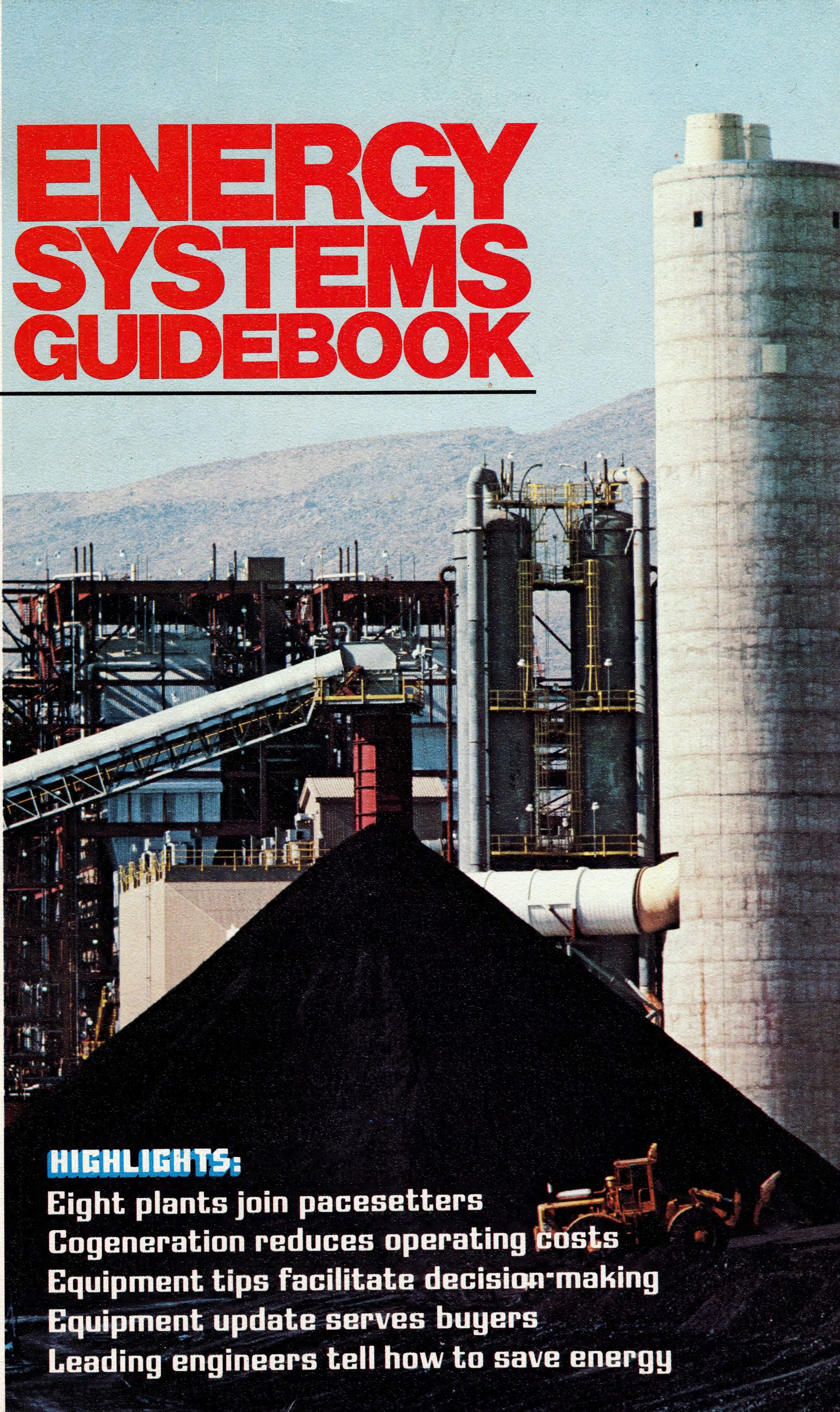
1980
The industrial plant...

ENERGY SYSTEMS GUIDEBOOK

By the Editors of **Power** Magazine



HIGHLIGHTS:

Eight plants join pacesetters
Cogeneration reduces operating costs
Equipment tips facilitate decision-making
Equipment update serves buyers
Leading engineers tell how to save energy

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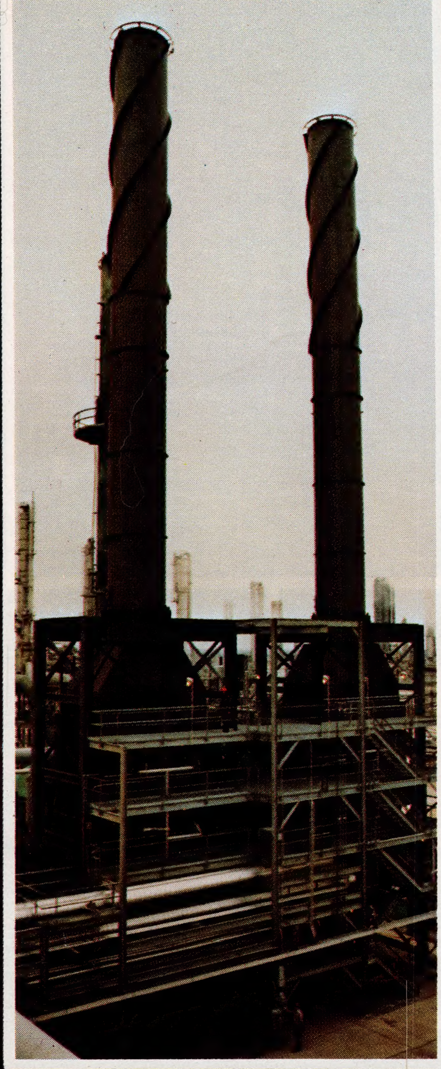

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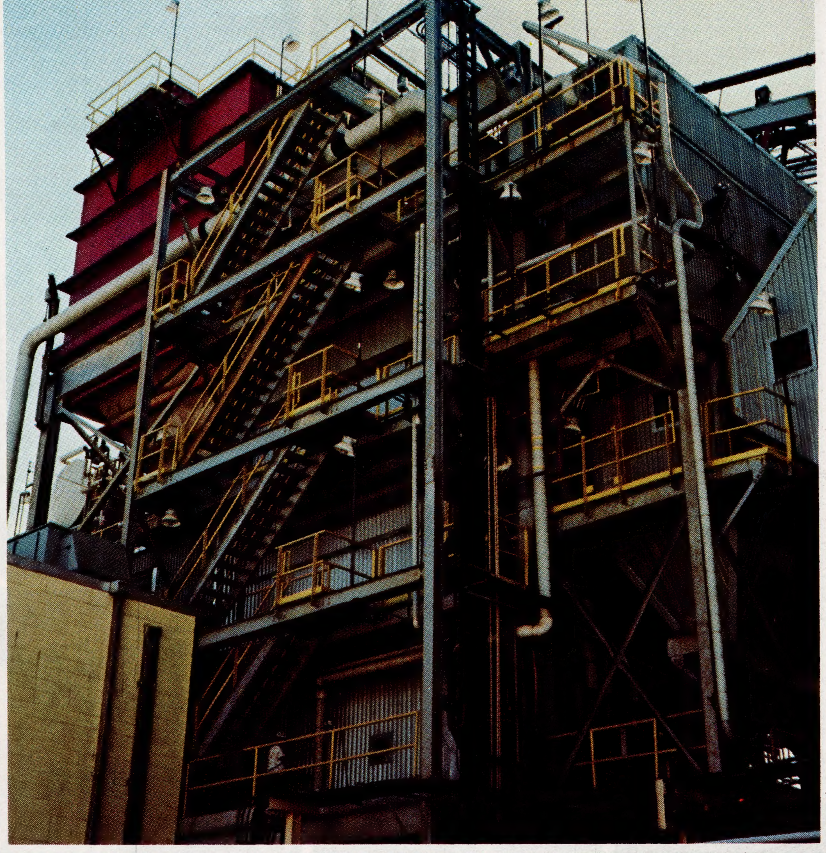

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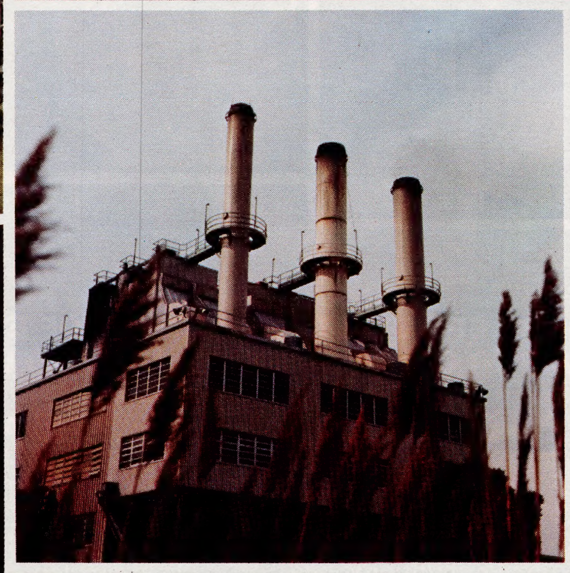
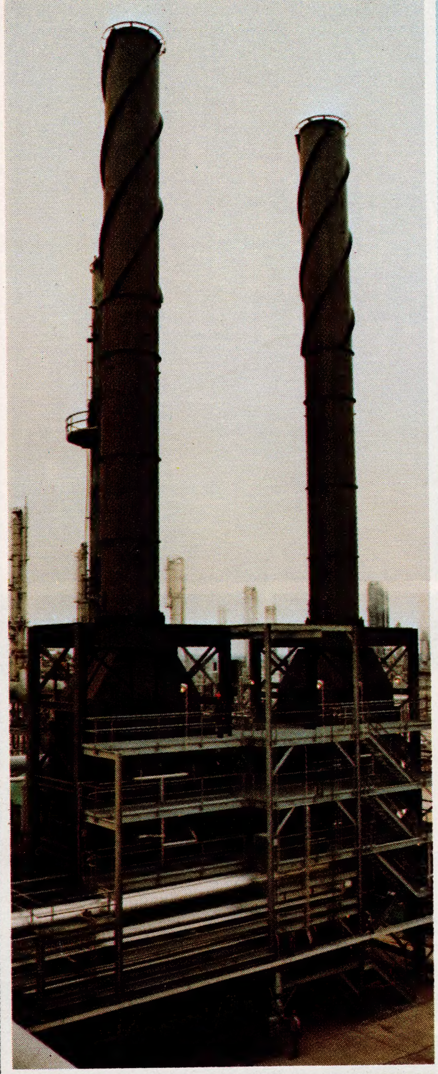


2

Convert and Conserve . . . through recovery of valuable hot gases. Zurn waste heat energy recovery systems *(Photo 1)* allow you to save vital fuel by "capturing" gaseous emissions such as blast furnace, coke oven, gas turbine exhaust, carbon monoxide - - and a variety of hot, noxious gases. Then, transforming these gases into high-quality steam at considerable savings.

Accent on Solid Waste Fuels as an energy alternative continues to receive considerable attention as industry strives to conserve traditional fossil fuels. Aiding in this effort, Zurn waste fuel energy recovery systems *(Photo 2)* convert inexpensive, industrial waste by-products such as tree bark, wood chips, bagasse, and waste liquids into valuable, economical BTU's of steam energy.

If Coal Is Your Goal as an energy source, Zurn offers a wide range of coal-fired steam generators *(Photo 3)* complete with spreader stokers for continuous or intermittent ash discharge. Users are also finding that the addition of a Zurn Economizer, to utilize often-wasted flue gas heat for increasing feedwater temperature, can further reduce energy costs by an additional 5% or more.



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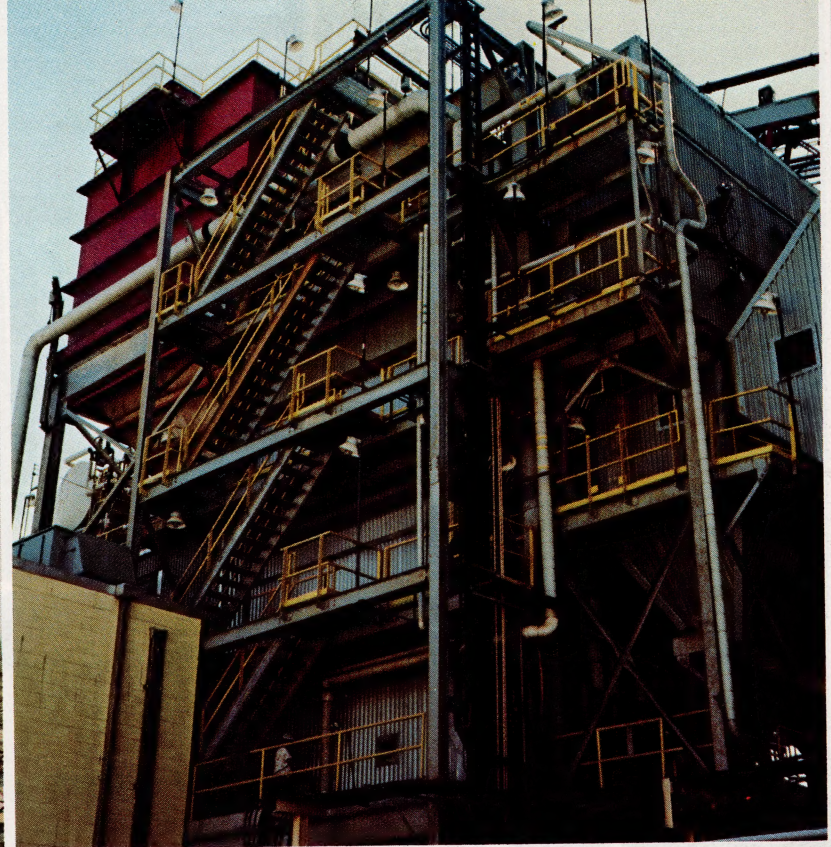

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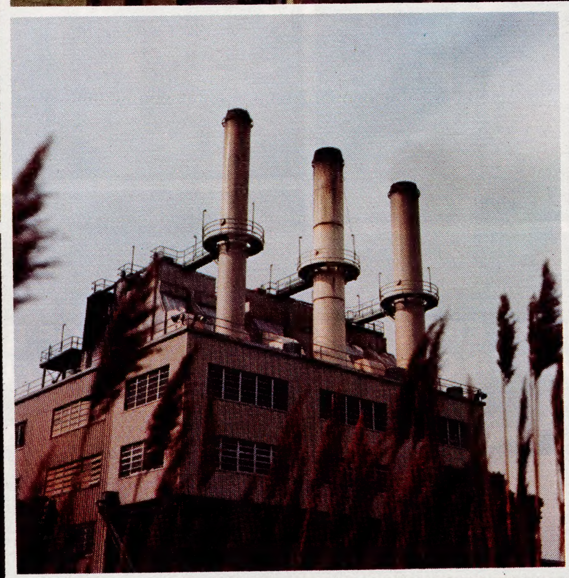

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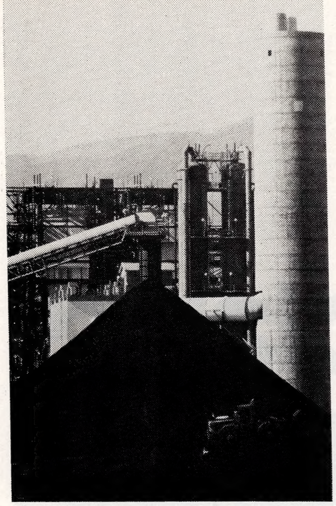

Kerr-McGee plant in Trona, California

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ENERGY SYSTEMS GUIDEBOOK

Trends

Pacesetter Plants

Cogeneration

Equipment Decision-Making

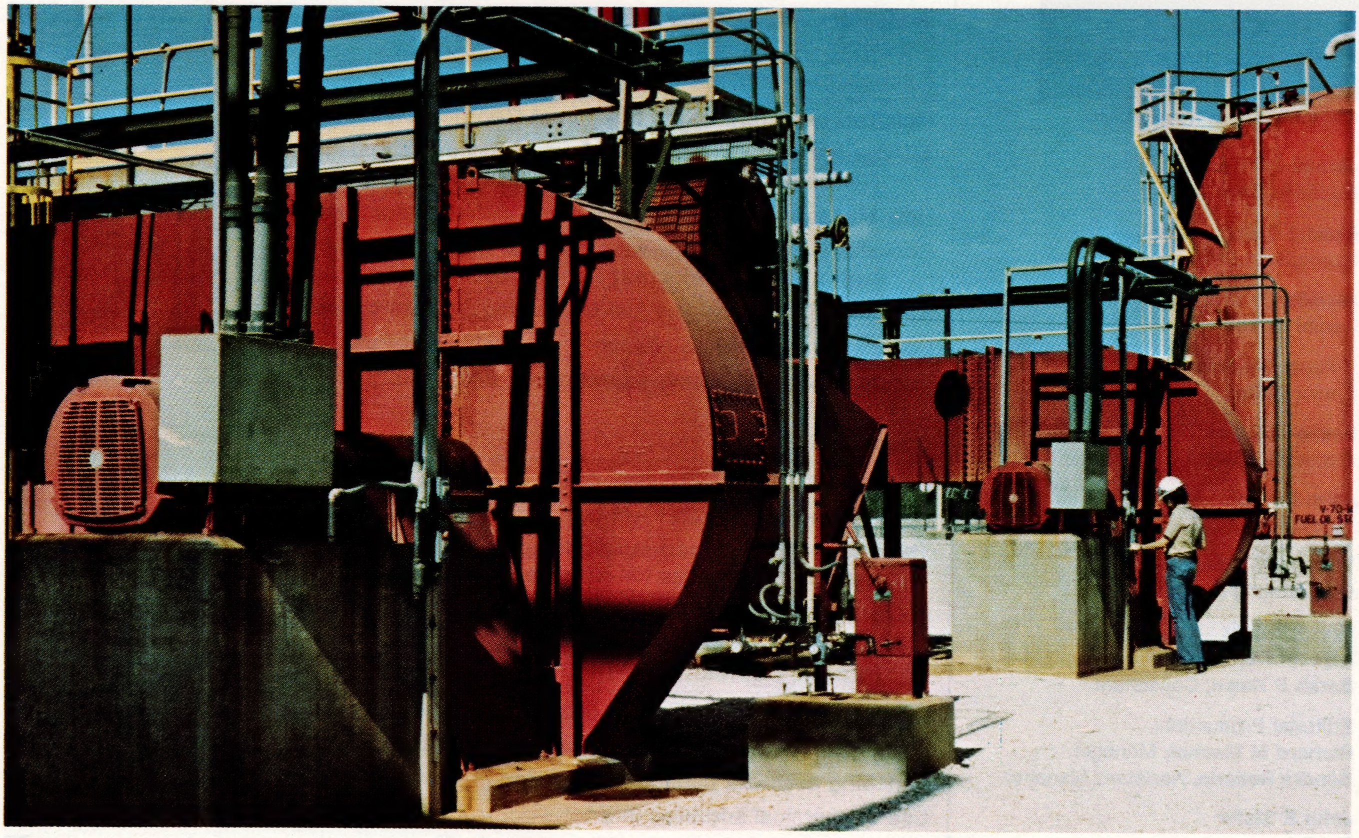
People in the Forefront

Designer's DataBank

Codes & Standards

Guide to Manufacturers' Literature

Clarage fans move the air for industrial power plants



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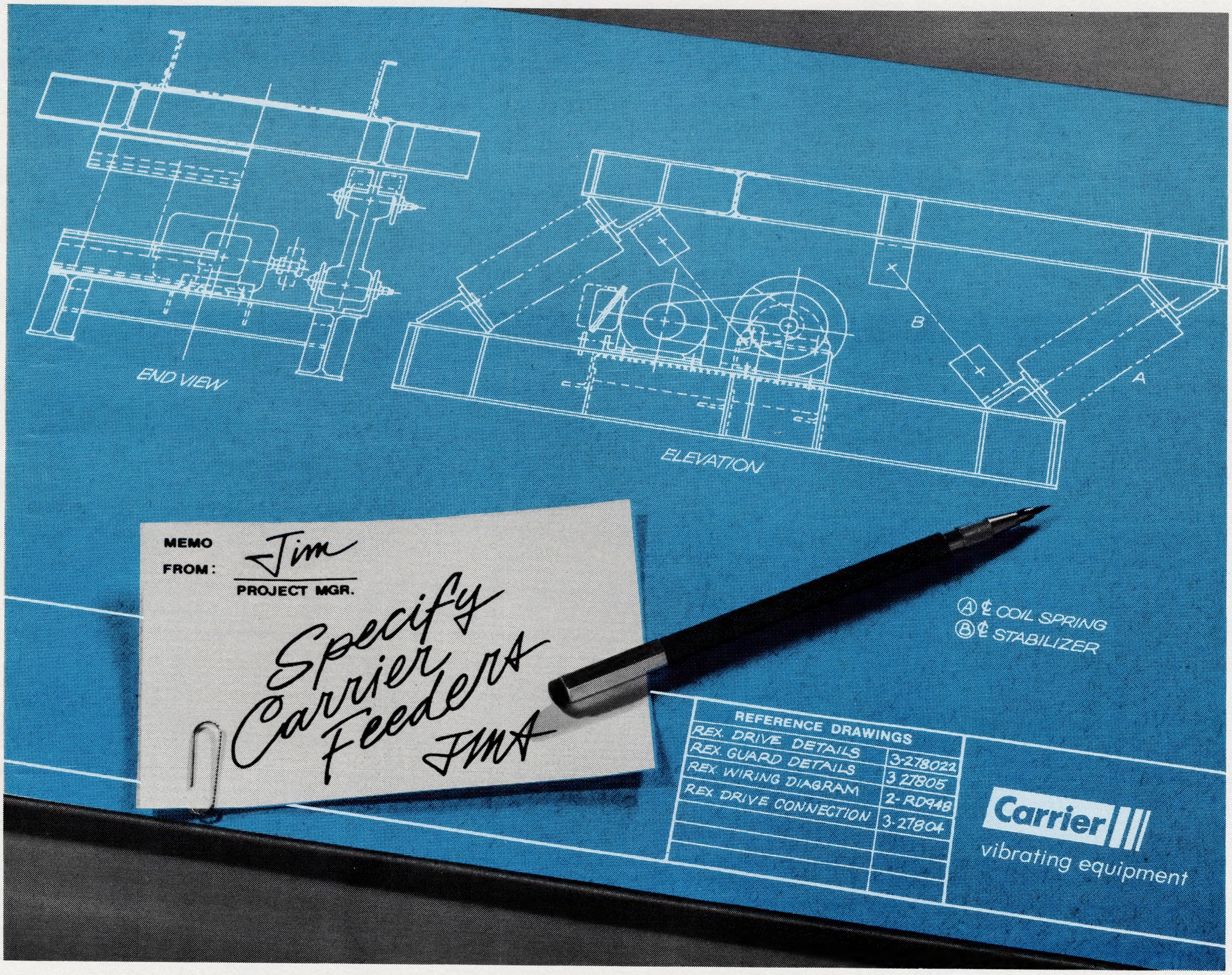

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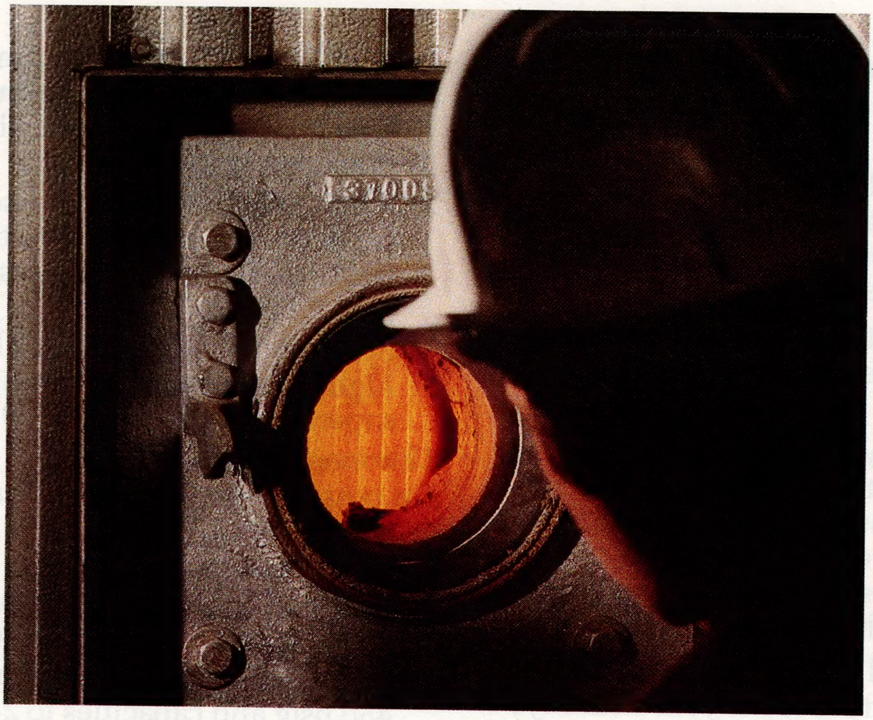
TRAP

CIRCLE 7 ON READER SERVICE CARD

Energy



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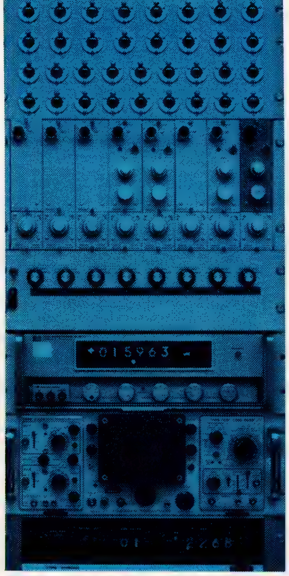
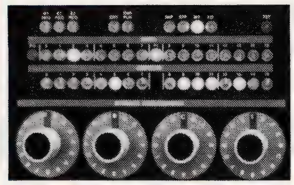
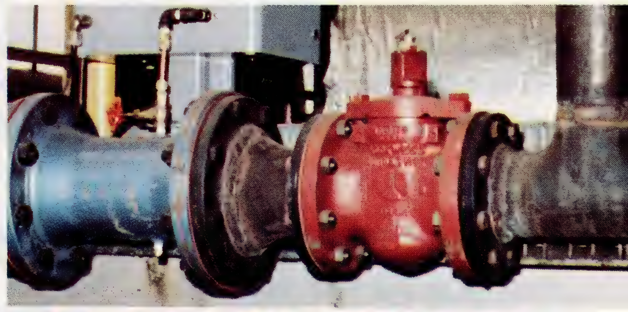
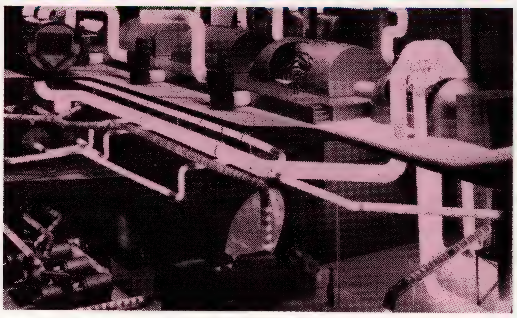
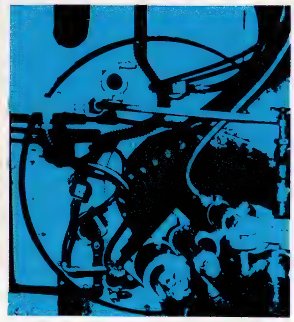










OVERVIEW

Efficiency and productivity: What they mean to the engineer

There is little disputing the elements ingrained in the ever-increasing importance of equipment and system efficiency. Moving apart from sophomoric terms, the engineer looks to minimizing losses that string throughout the broad area of energy systems.

As you study each section in this Guidebook, note the variety of approaches used by energy-systems engineers to attain ever-greater values of system efficiency. The most straightforward and classical example, for many, is the energy-audit procedure at Elliott Co, which may well serve others who are trying to maximize the return on their investment in raw fuel and electrical consumption. Efficiency, too, is the keynote in Rust Engineering Co's account of its modeling methods for planning new steam and cogeneration systems. Efficiency comes to the front as modeling eliminates the need for some detailed drawings while facilitating maintenance plans and pinpointing likely trouble spots before plant construction gets under way.

And if you weigh the thinking of four leaders in the field—Levi Leathers of Dow Chemical USA, Ed Holden of General Foods Corp, Frank Feeley of Olin Corp's Chemicals Group, and Gerry Gambs of Ford, Bacon & Davis Inc—you will note the efficiency thrust running throughout their comments. They look at problems facing industry today and discuss likely solutions, with efficiency at the forefront.

Productivity is, by classical definition, effectiveness in using labor and equipment. We find the economist staying close to units produced as a function of labor input. I look upon productivity in a slightly different light, and I believe my analysis is shared by many practicing engineers today. In brief, productivity is the amalgamation of quantity *and* quality.

It means little indeed to the corporate energy-systems engineer that the manufacturer is turning out power equipment for his project at a suitable rate, if the quality falls below the standards he demands. It means little, in the long run, that quality equipment is delivered on site and on time, and installed on schedule, if the factors of quality that will regulate equipment life are downgraded by sloppy installation practice.

Yes, quality has generally been assumed when we speak of productivity. Yet, in real life, it may fall short anywhere from equipment manufacture, to equipment installation, to initial testing, to operation, to maintenance and repair.

In my judgment, productivity spans the life of equipment, and should never be relegated to the simple aspect of counting units being formed as a function of the labor and equipment being used. I propose that you keep these thoughts on efficiency and productivity in the forefront as you adapt the host of ideas contained in the 1980 Energy Systems Guidebook.

James J O'Connor

Designing tomorrow's powerhouse

Its builders still have to resolve such familiar, hardnosed questions as: How much does it cost, what's the return on investment, will the government let us do it? Here are some options (and constraints) to consider

By Thomas T Dingo, General Motors Corp

At General Motors Corp, engineers are quite concerned about the subject of future steam-generating plants. In many cases, the company's ability to install and operate powerhouses can affect expansion plans, new plant locations, and even process modifications. Moreover, since the normal life of a boiler is 30 years, what GM installs today will be operating for many years in the future—so today's plans have to be enduring.

This article discusses several recent developments that should be considered when designing new boiler plants. Some of the developments are being incorporated into GM's powerhouses currently on the drawing boards; others are being studied closely for possible incorporation in future plants. The primary focus is on the developing technology for boilers, control systems, auxiliary equipment, and alternate fuels.

Factors affecting future designs

Before discussing the technical aspects of new plant design, let's pause to look at some of the factors that are exerting pressure on future designs. In the old days, the job of designing a power plant was comparatively simple. The designer:

- Determined the process and/or space-heating requirement of the addition or new plant.
- Identified the cheapest and most reliable fuel for his boiler.
- Selected the transport media—steam, hot water, or thermal liquids.
- Selected combustion equipment.
- Added the auxiliaries to run the boiler and, to be a good neighbor, selected a simple particulate control system.

Today, however, this procedure has been altered drastically. Unfortunately, many of the specific decisions either have been made for industry, or have been biased significantly by government controls and mandates. No longer can decisions be based on what is the most economical and reliable way to generate steam. Rather, they are based on how industry must comply with the rules in the Powerplant & Industrial Fuel Use Act and New Source Performance Standards (NSPS) for boilers.

The Fuel Use Act was enacted Nov 9, 1978. Generally, it prohibits the use of petroleum or natural gas in new facilities and provides DOE with authority to issue orders prohibiting existing facilities from using petroleum and natural gas. DOE, however, can issue exemptions to cover physical, economic, environmental, and legal factors that preclude compliance with the prohibitions. The quite substantial burden-of-proof of demonstrating that an exemption is warranted rests on the fuel user.

One of GM's greatest concerns in the implementation of this act is the time and effort that must be expended to apply for an exemption to comply with its provisions—particularly for those facilities that will be built where it is impossible to comply with environmental laws and still burn coal. The procedure in the Fuel Use Act may result in up to a two-year delay in the period between the planning of a facility, the granting of its environmental permit (or denial of such), and the final granting (or denial) of an exemption. Even if DOE grants an exemption, it may contain harsh conditions.

Another concern with the Fuel Use Act is the procedure to justify an exemption because of economics. As proposed, the act will allow permanent exemptions if a petitioner demonstrates that the cost of using coal, or an approved alternative fuel, will "substantially exceed" the cost of using imported petroleum for at least the first ten years of operation. In DOE's interim final regulations, "substantially exceeds" means that the ratio of the cost of using coal to the cost of using oil must be 1.3 or greater.

At first glance, a cost index of 1.3 appears reasonable with an equal probability of some units both qualifying for and being denied exemptions. Closer analysis shows, however, that exemptions at the 1.3 ratio may be hard to obtain. The general cost test in the act defines cost as the sum of the annual outlays for capital, operation and maintenance, and delivered fuels, discounted to the present. When performing the cost test for a 250,000-lb/hr steam plant where the capital required for coal firing is four times that for oil firing and the operation and maintenance costs of the coal plant are three times that of oil (an unlikely situation), surprisingly the test only gives a ratio of about 1.5. Thus, it appears that virtually all new boiler plants will be coal-fired.

If coal usage is to increase, the industrial user is faced with another problem: How does he burn coal and comply with existing environmental laws? Currently, the only answer is through the investment of significant capital and added operating costs. To compound the problem further, new environmental laws, which promise to be even tougher, are in development.

NSPS for industrial boilers are also in the development stage and will be proposed in 1980. Industry has been told what the range of emission levels will be. For particulates, it will be necessary to hold emissions between 0.03 and 0.25 lb/million Btu. For SO_2 between 0.2 and 1.2 lb/million Btu (with possibly some percentage removal of sulfur from the coal); for NO_X, between 0.5 and 0.7 lb/million Btu. It is hoped that the proposed standards will be fair, take into account the true environmental impact of the typical industrial powerhouse, and will not legislate out promising new technology. Compliance choices are already few in number.

Emerging technology

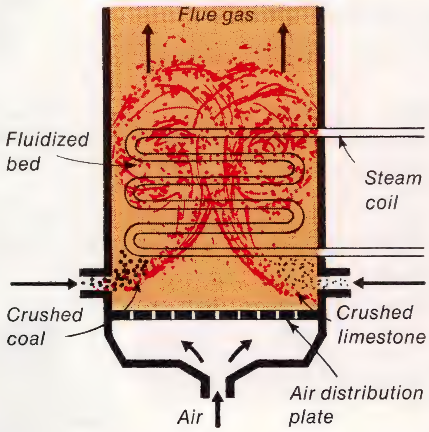
The Fuel Use Act and NSPS will have a significant impact on the engineering and design of future industrial powerhouses. Future designs will have to consider these technologies that have just been developed or are emerging.

Fluidized-bed combustion technology is well established for incinerators and catalyst regeneration processes (Fig 1). Only in recent years, however, has interest grown in fluidized-bed combustors for steam generation, primarily because of public concern over gaseous emissions from stacks, and problems arising from the relative cost and availability of fuels currently being used.

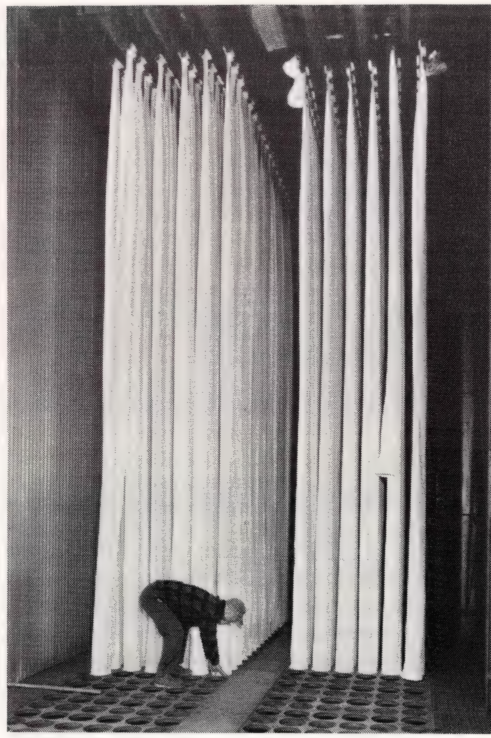
Recall that a fluidized bed is a mass of granular solids held in turbulent suspension by an upward current of air. The

mixture of air and solids exhibits the properties of a fluid. Theoretical advantages include:

- Emissions from fluidized bed boilers may meet New Source Performance Standards for SO_2 and NO_x without the need for auxiliary controls. Sulfur oxides are removed in the combustion zone by limestone, which makes up a large proportion of the bed material. NO_x emissions are inherently low because of the relatively low combustion temperatures.
- Fluidized-bed boilers may have the versatility of using a wide variety of fuels, including such low-quality fuels as high-ash coals, and they have multifuel capability, being able to accommodate solid, liquid, or gaseous fuels.
- Fluidized-bed boilers should have lower capital costs than conventional boilers because of lower heat-transfer-surface requirements and no requirements for auxiliary gaseous-emission control systems.



1. The fluidized-bed boiler has particular application in controlling stack emissions from coal-fired units



2. Baghouses are becoming increasingly attrractive as a device for meeting particulate emmission limits, especially when low-sulfur coal is burned

The lack of widespread commercial sales by manufacturers is the result of several unresolved questions about fluidized-bed boilers, including economics (capital and operating costs), combustion efficiency, turndown and response, emission levels, coal feed, and reliability of the related mechanical system. It is hoped that demonstration projects planned by DOE will answer some of these questions and lead the way to the commercialization of this attractive coal-burning method.

Until these questions are resolved and the fluidized-bed boiler is priced to give some economic incentive, however, its widespread use in industrial powerhouses for the near future is doubtful. Thus, it appears that combustors for at least the near term will continue to be the proven pulverized-coal and spreader-stoker boilers.

Controls use microprocessors. Although GM will continue to use conventional boilers, one of the major changes company engineers intend to incorporate into their plants is automatic feedback control of air/fuel ratios. Such controls are becoming more popular because of the continuing increase in the cost of fuels and because tighter excess air control can lower NO_x emissions. The trend is toward electronics and computer technology.

Many control manufacturers can supply automatic feedback, air/fuel ratio controllers. Most GM boilers have low utilization factors, however, because their steam is used basically for space heating and air tempering. Thus, the proposed automated control system cannot be so sophisticated and hardware intensive that the company realizes no payback for incorporating the additional equipment. Also, new boilers will be coal-fired, with the majority being spreader stokers. Because of the nature of stoker firing on a moving grate, therefore, oxygen cannot be the only control parameter.

Unfortunately, not too many suppliers understand GM's needs. To overcome this, the company started its own development program on boiler controls about two years ago—a program aimed at both new and existing boilers. The objective was to minimize the amount of excess air in the boilers without disrupting the combustion process. Theoretically, by reducing the excess air from 100 to 70%, 2% less heat is lost through the stack. If the decreased stack gas temperature (due to the longer contact time across gas-heat-transfer surfaces) is also taken into account, the heat loss is reduced potentially by 4%. In simple terms, the less air, the less fuel required to heat it.

System details. In conventional systems, the deviation of the steam pressure signal from setpoint regulates the flow of fuel and air. The ratio of these two flows varies as a function of the steam load. Also, in full-metering systems, fuel and air flow is measured to check the ratio. The proper ratio is established and set by the control manufacturer, with enough safety built in to avoid smoking during rapid load changes. In other, more sophisticated systems, oxygen analysis of the exhaust gas is used to provide tighter, more direct control. In stoker-fired boilers, however, engineers are not sure this is enough.

Engineers go one step further in the system GM has been developing. Feedback signals from the stack, which indicate the true quality of combustion, are included. These signals are generated by an in-stack oxygen analyzer and a smoke-density meter. One signal indicates the amount of air used for combustion and the other the completeness of combustion. The opacity signal keeps lowering the air/fuel ratio until the signal from the oxygen analyzer limits it, or opacity reaches a maximum setpoint. By doing this, the system automatically finds and maintains the lowest possible air/fuel ratio without opacity violations for a wide range of operation.

The heart of the system is a small microprocessor that takes the flue-gas signals, interprets them, and feeds a control signal to the induced-draft and forced-draft fans and the coal feeder to set the proper ratio. Thus, the boiler is operated objectively at maximum efficiency without smoking.

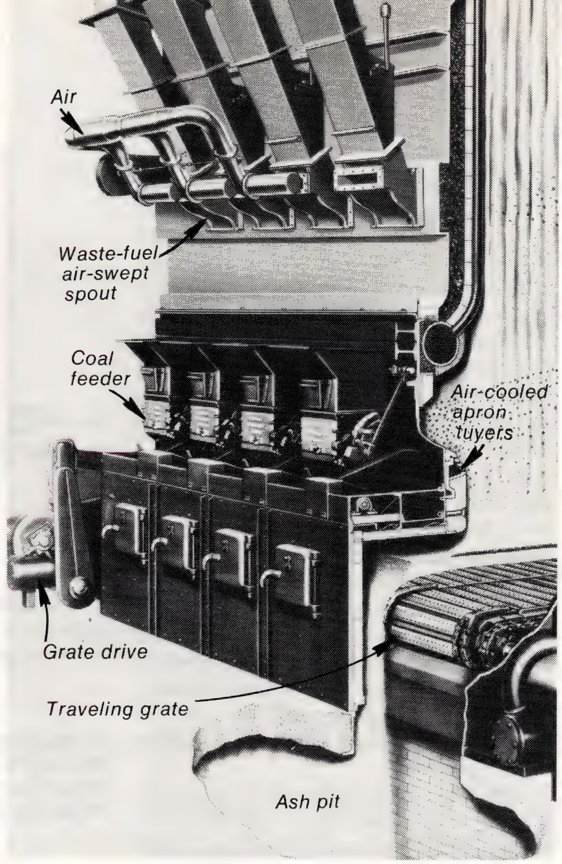
For the past two years, a prototype has been undergoing extensive testing to determine equipment reliability and efficiency improvements. Comparative testing, conducted by switching back and forth between the existing control board and the microprocessor every 8-hr shift, has shown a 4% boost in efficiency with the feedback system. The sequence was randomly spaced to avoid error from uncontrolled variables such as operator actions, load, coal quality, etc.

One of the main reasons GM decided on a microprocessor to do the controlling is that engineers believe this new technology offers the most flexibility at the lowest cost—around $6000 per unit. The

Compare properties of SRC-II with those of coal

Fuel properties	SRC-II	Parent coal[2]	No. 6 oil	No. 2 oil
Ultimate analysis				
Carbon, %	866	72.2	86.61	86.82
Hydrogen, %	8.38	5.0	12.25	12.69
Nitrogen, %	1.12	1.4	0.24	0.024
Sulfur, %	0.26	3.6	0.28	0.11
Ash, %	0.008	10.5	0.016	0.003
Oxygen, %[1]	3.63	7.3	0.6	0.35
Higher heating value, Btu/lb	17,040	13,150	19,150	19,190
Gravity, deg API at 60F	8.3	—	2.3	32.3
Viscosity, SUS at 140F	35.6	—	324[3]	34

Source: KVB Inc. [1]Determined by difference [2]Western Kentucky coal [3]Viscosity measured at 100F



3. Combustion of solid waste is feasible in industrial applications large enough to justify the capital investment

whole control package—instrumentation and installation—costs about $25,000. With a typical boiler using 10,000 tons of coal annually, the payback from a 4% improvement in efficiency is two years.

Emission-control systems. The area in which the most visual and prominent change for future powerhouses will occur is in back-end emission-control systems for particulates, SO_2, and NO_x. Remember that existing and developing federal and local emissions codes will force the industrial coal user to apply sophisticated equipment in many cases.

For particulates, it appears that companies can no longer rely on the multiple cyclone mechanical collector to meet the law. Instead they will turn to electrostatic precipitators and baghouses.

Precipitators have seen service for years on pulverized-coal-fired units because they are effective in removing minute flyash particles. They are especially suited for large boilers; however, capital costs in size ranges below 50,000 cfm are high. One of the major drawbacks to using them are their sensitivity to dust resistivity, especially for low-sulfur coals. Although hot-gas precipitators may alleviate the sulfur problem, such units have large space requirements and lead to high first costs.

Because of these problems, GM is looking to baghouses to meet the required particulate emission limits (Fig 2). Compared to other devices, a baghouse may be classified as a relatively constant emission device. That is, as the inlet grain loading, particle-size distribution, temperatures, flows, etc, vary, the outlet loadings remain about the same. Thus, baghouses will allow reinjections of collected fines back into the boiler without opacity or emission violations.

A concern with baghouses, however, is their sensitivity to extreme fluctuations in gas temperature. Blinding of the bags can occur unless the unit is operated at temperatures above the acid dewpoint. Unfortunately, such operations can lead to corrosion of the metal surfaces and greatly shorten bag life. At the other extreme, high temperatures must also be avoided. A glass fiber, Teflon-treated bag has a maximum operating temperature of 550F; a bypass duct should be installed to avoid overheating.

For SO_2 control, several approaches are available. Because GM relies on relatively small boilers to produce steam—that is, compared to electric utilities—and because of the company's minimal contribution to the SO_2 ambient levels, engineers think that the burning of low-sulfur coal (less than 1% sulfur) is the most logical approach. The hope is that EPA realizes this and will not formulate the New Source Performance Standards for industrial boilers to require a percent reduction in SO_2. If such a reduction is required, GM and others will have to use some form of flue-gas desulfurization (FGD).

Currently, the most common method of FGD is wet absorption into an alkaline solution. GM has several systems using sodium salts already in operation. Experience in operating these systems shows that they do an excellent job of removing sulfur, but are expensive to run and maintain. Because of the mist carryover characteristics from scrubbers, however, engineers doubt they could meet the projected particulate and sulfur limits at the same time. Thus, for future plants, a dry scrubber (such as a spray dryer absorber) may be the most attractive method of control.

This type of FGD has several inherent advantages over wet systems. The dry scrubber/absorber should have lower capital costs and draft losses, require less plan area for installation, consume less water, and provide reliable, low-maintenance operation. If there are any shortcomings to the system, they may be higher operating costs and lower removal efficiencies.

Pilot operations that have been conducted report SO_2 removal efficiencies from 78 to 85% at 1.3 alkaline to lime stoichiometry. Anything greater than 85% removal would require too high a consumption of lime or caustic to be economical. Also, depending on where the new NSPS levels are set, 85% removal efficiency may not be enough for high-sulfur coals. Generally, the technology appears technically and economically feasible for coal with less than 2% sulfur content.

For nitrogen oxides, the control scheme will depend greatly on the NSPS levels and the type of boiler selected. Some auxiliary control methods, such as wet scrubbing or catalytic reduction, are being pursued but it is doubtful whether such approaches could operate reliably or economically on coal-fired units. The most probable and logical alternative is tight air/fuel ratio control.

Because of their design and combustion characteristics, spreader-stoker boilers do not produce significant amounts of NO_x. In effect, a stoker boiler has a degree of staged combustion built into it via its over- and under-fire air system. Further NO_x reduction could be achieved by using the same automatic feedback control of the air/fuel ratio to help improve efficiency.

On pulverized-coal-fired boilers, the approach will differ only slightly. Again, tight control of the air/fuel ratio will be practiced, but at each individual burner. Also, the air/fuel ratio of the burner will be varied (rich or lean) to give the effect of staged combustion. This approach is working well on utility boilers and should prove practical for industrial applications, too.

Alternative fuels. As mentioned, the Fuel Use Act prohibits the use of natural gas and petroleum in new industrial boilers above 100-million Btu input and provides certain exemptions for the use of alternative fuels. Many of the alternative fuels recognized for exemption are still in the technical and economical demonstration phases. Several have the potential, under some extreme circumstances, to be part of a future powerhouse.

One of those fuels is a coal/oil mixture (COM), which is a mixture (by weight) of 50% pulverized coal in No. 6 fuel oil. On a heating-value basis, coal replaces about 35% of the oil. Also, a stabilizing agent, additive, or some other preparation, may be included depending on handling and time for using the fuel.

In the past couple of years, several demonstrations of COM have been initiated; GM completed one in 1977. In that test, over 300,000 gal of COM were burned during a 750-hr period in a 120,000-lb/hr boiler designed for oil and gas. Our results showed that COM gave the same flame characteristics as No. 6 fuel oil, that no slagging or ash problems occurred in the boiler, that boiler efficiency was not affected, and that emissions should be able to be controlled with commercially available equipment.

The use of coal/oil mixtures in future facilities may be justifiable in special situations. One of the main advantages of COM is that it can be handled and received in the same manner as No. 6 fuel oil. Thus, it is well suited for sites with serious space limitations where a coal-handling facility could not be built, or where no coal distribution infrastructure exists.

The major deterrents to its use by industrial-boiler operators may be economics and availability. Because of the size and utilization factor of typical industrial powerhouses, most potential users of COM could not justify the cost of installing a COM preparation plant. In most cases, the industrial user must be able to purchase COM from a central preparation plant. Currently, prospective producers are proceeding cautiously and are waiting for a market to develop.

Another fuel alternative that would be exempt from the prohibitions of the Fuel Use Act is solvent-refined coal in liquid form—so-called SRC II. SRC II is produced by an advanced coal-liquefaction process in which raw coal is mixed with a product slurry and hydrocracked to liquid and gaseous products. The dissolved coal, unconverted to distillate and lighter products, is sent to a gasifier along with the undissolved mineral residue to produce hydrogen for the process. The primary product from the process is a distillate oil that is very similar in physical properties to a No. 2 fuel oil, but has the heating value of a No. 4 oil (see table).

SRC II has several attractive characteristics. The oil can be transported in pipelines and stored in tanks like petroleum distillates without extra heating or recirculation. With 90 to 95% removal of the sulfur and virtually all the ash, this fuel, with proper combustion control, meets existing and proposed emission standards.

DOE and the Electric Power Research Institute have funded much of the research for this fuel. A 1-ton/day pilot plant has been operated for several years by a subsidiary of Gulf Oil Corp. Recently, 4500 bbl of SRC II were test fired at a Consolidated Edison Co of NY plant with very favorable operating and emission results.

For industrial-size boilers, the potential large difference in capital, operating, and maintenance costs between (1) a solid-fuel-fired, field-erected boiler with emission controls and a typical low utilization factor and (2) a shop-fabricated liquid-fuel-fired facility, provides strong economic incentives to considering SRC fuel oil rather than converting to coal.

Future philosophies

Industries must lean to assess how future steam generation can fit into their total operations at the least cost. For some, the approach could be solid-waste combustion. For others, it may be heat recovery of waste energy. For a few, it may be a decision not to install anything new purely because of economics.

Solid-waste combustion. The burning of combustible municipal waste in utility central stations is becoming more common. Systems similar to these are feasible for industrial applications large enough to justify a sizable capital investment. This approach is attractive in light of the increasingly more restrictive regulations and the growing cost of solid-waste disposal. GM is currently operating such a facility, using industrial plant waste.

The facility uses multifuel-fired boilers equipped with spreader stokers for coal and air-swept spouts for solid waste (Fig 3). Equipment includes a building as large as the powerhouse for receiving and preparing the waste, a 1400-hp horizontal shaft hammermill for shredding, and a 600-ton live-bottom bin for storing the fuel. The system is designed to burn 55,000 tons of solid waste annually, replacing roughly 33,000 tons of coal and yielding about a 3-yr payback. As older boilers at GM are replaced, the ability to use multiple fuels, including solid wastes, will be a design consideration.

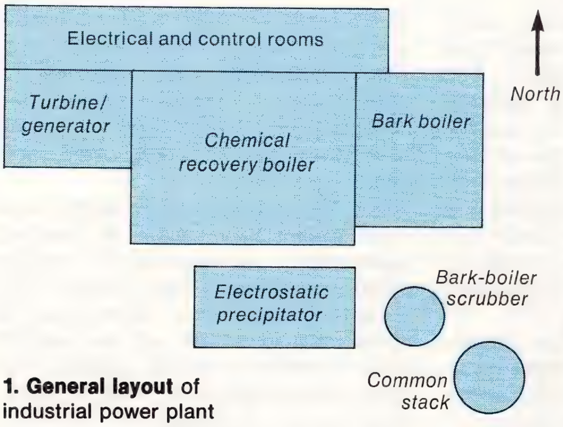
For the majority of industry, such large installations cannot be justified economically. An approach for smaller plants may be incineration coupled with a heat-recovery boiler. Advantages of incineration as a first step are smaller capital investment and the capability for using unprepared waste, such as cardboard, wood, and pallets.

Waste energy to generate steam. Not all segments of industry will be able to justify solid-waste combustion because of insufficient volume, site limitations, or excessive cost, but some segments may be able to use waste exhaust gases to generate steam. Many industrial plants give out gases that have fuel value and/or pose an environmental control problem. Coupling steam generation with the control of these emissions may provide a viable, economic alternative to a new direct-fired, fossil fuel boiler. Examples of processes where this scheme may be attractive are at the exhaust of a cupola, solvent incinerator, or high-temperature heat-treating furnace.

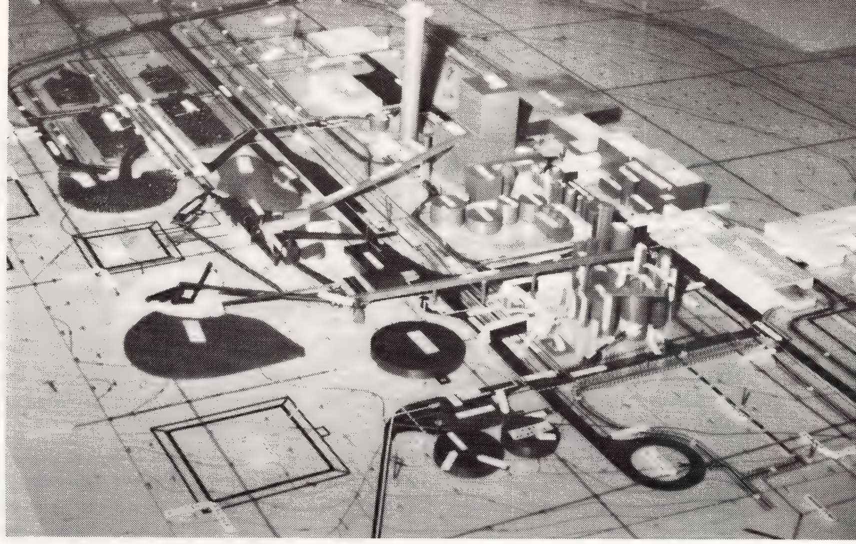
Currently, application such as these cannot be justified economically. In the light of future emission regulations, however, and the rising cost of installing a coal-fired powerhouse, steam generation using waste heat will become more attractive.

Wrapping it up. The powerhouse of the future will be deeply affected by emerging energy and environmental regulations, and will include new equipment and technology, alternative fuels, and new operating concepts. How tomorrow's industrial powerhouse is regarded, however, depends on one's viewpoint.

A corporate accountant will see it as a massive capital expenditure with the ever-present potential for disrupting his profit picture. The environmentalist will see it as a clean and long overdue example of what industry can do when it is forced to comply with environmental regulations. The energy supply expert will see it as a classic case of using our most abundant natural resource—coal—in a direct and orderly fashion. The design engineer will see it as a bristling but welcome challenge for showing off the latest technology in a tight energy economy. The plant engineer will see it as a possible maintenance headache, and probably overlook the noteworthy technical advances. Finally, the oldtime powerhouse chief may view the powerhouse of the future as the "tail wagging the dog" and start counting the days until his retirement. ■



1. General layout of industrial power plant blocks out key elements



2. Small-scale site model permits plant overview. Note that the location of the power generation complex is in the center of the plant

TRENDS

Modeling for industrial power

Long established as a vital design tool in process and manufacturing, modeling now shows signs of becoming a design trend for industrial plants

By Clark A Mason, Rust Engineering Co

The use of scale models as design and construction tools in the refinery and process industries has become highly developed in this country during the last quarter century. Today, most design contractors serving these industries provide modeling services.

Rust Engineering Co was one of the early design and construction contractors to apply scale modeling to the manufacturing industries. The company's modeling activity, which began in the late 1950s, has continuously expanded, and today it maintains large, fully integrated modeling departments in two of its offices.

Activity has ranged from architectural models of hospitals and large buildings, civic and industrial planning models, working models of industrial equipment and coal-fired utility power plants, to a variety of models for the pulp and paper, metallurgical, chemical, and other manufacturing industries—many containing sizable industrial power plants. In fact, Rust engineers see the last-named as a future trend for modeling among design contractors.

The pulp and paper industry traditionally has generated a major portion of its electrical power from bark and wood waste, natural byproducts of this industry, and from process chemical-recovery boilers (Fig 1). As a major consultant to this industry, industrial power modeling has been a natural development for Rust.

Advantages of models

Models are developed for a variety of purposes and uses. Some of the primary advantages to be gained by model usage are:

- As aids in laying out equipment for the best use of space and product flow—especially important in retrofit jobs.
- For construction planning studies, important in modernization programs, and often resulting in a major impact to the critical path.
- As a construction tool. The model, which is easier to work from than drawings, is issued to the field in lieu of orthographic drawings.
- For review by potential construction subcontractors to ensure a full understanding of the scope of work.
- For installation of piping directly on the model from piping and instrumentation diagrams, helping to optimize piping runs, and to permit scanning and other input devices for computer-automated isometric drafting of piping.
- To facilitate alternative studies for cost reduction during planning stages.

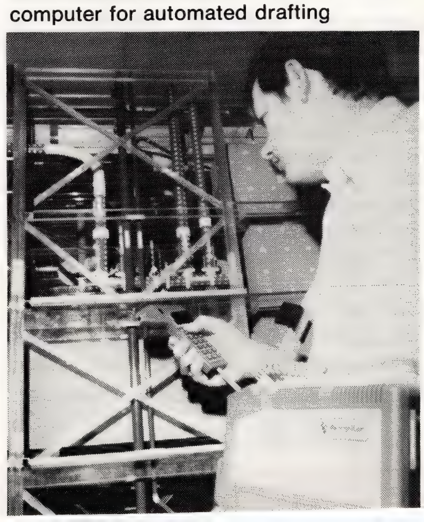
Secondary advantages of model usage are:

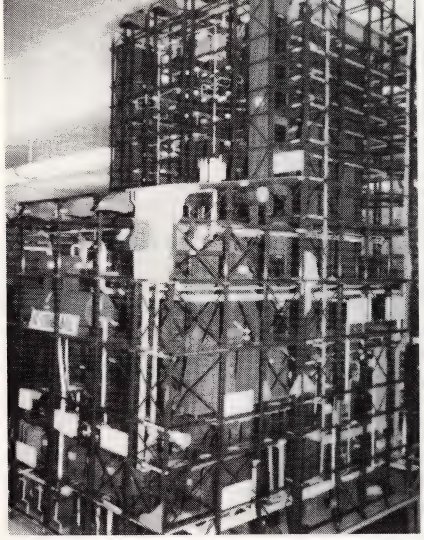
- To facilitate high-level reviews by the client's and the engineer's management personnel.
- As a training aid for the client's operating and maintenance personnel.
- To facilitate review of the project by nondesign personnel—for safety, environment, insurance, etc.
- As a training aid for the orientation of new engineering and construction personnel.
- For public-relations purposes.

Selecting the model scale

Model-scale selection depends on the model's end use. Small-scale models in the $1/25$-$1/50$-in./ft range are generally selected for public-relations purposes or overall site development. Models of about $1/25$ in./ft provide adequate detail

4. Piping input is taken directly from final model. Data are recorded for input to computer for automated drafting





3. Definition model (3/8-in. scale) shows size relationship of recovery boiler (right) and bark-fired steam generator (left)

to permit an overview of the interworking relationships of major equipment, plant operating units, and buildings, and are excellent for overall site development (Fig 2).

For industrial power complexes, scale definition models, 1/4 in.-3/8 in./ft, generally find wide application in developing further definition of the project in the early engineering stages (Fig 3). These *definition models*, with equipment often made from catalog cuts or proposal drawings, permit engineers to experiment with various layouts and orientations to best use available space and optimize building configurations and piping runs.

After agreement of the general layout is reached, the definition models are usually refined by referring to selected vendors' proposal drawings and typical shop drawings for previous projects. Major piping runs down to 2 in. in diameter generally are shown and space is provided for electrical runs and heating and ventilating ductwork.

Additional capacity, as well as future requirements, can be considered during the initial stage of the project. These needs can be estimated and space planned for or reserved in the model.

Definition models can be further refined by adding details from all design disciplines. At this time, the model can be completely reviewed by the project team (client, engineer, contractor), and the general plant layout can be frozen. Additional high-level management reviews can be held.

With the definition model frozen, it becomes the basis for preparation of conventional orthographic drawings from which the power complex will be built, or for a large-scale detail model. Factors affecting this decision include the client's preference, plant location, schedule requirements, and cost.

A larger final detail model is often prepared from the definition model, usually at a scale of 3/4 in./ft. This scale permits extremely fine detail of the equipment, and is accurate enough to coordinate location of equipment, piping, and ductwork—all of which can be taken directly from the model (Fig 4). Orthographic drawing requirements are greatly reduced.

Once construction of the 3/4-in. scale model has been started, checks can be made by operating personnel to verify necessary access routes normally taken during operating tours, and by maintenance personnel to verify the access space available for servicing equipment. The latter can use scale models of portable equipment—such as fork lifts—to ensure proper access for normal maintenance. Frequently, the reorientation of pumps, motors, and similar small equipment can be made during these reviews to improve maintenance access without adding to project cost.

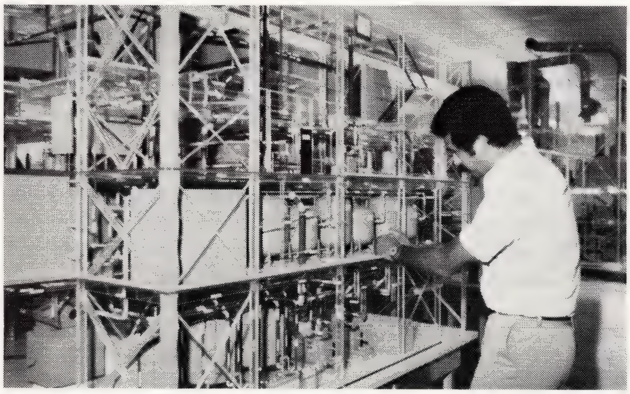
On both definition and detail models, color coding is used extensively to indicate type of service, types of equipment, and/or future requirements (Fig 3). With color coding, priorities can be placed on available space for more critical and costly items, such as steam turbines, feedwater pumps, and high-pressure steam lines.

A current modeling project

Work is well under way at Rust's Birmingham office on a 3/4-in./ft detail engineering model for a new pulp plant, which the Buckeye Cellulose Corp—a wholly owned subsidiary of Procter & Gamble Co—is building near Oglethorpe, Ga. Scheduled for completion in 1981, this model will be issued to the field for construction purposes instead of orthographic drawings.

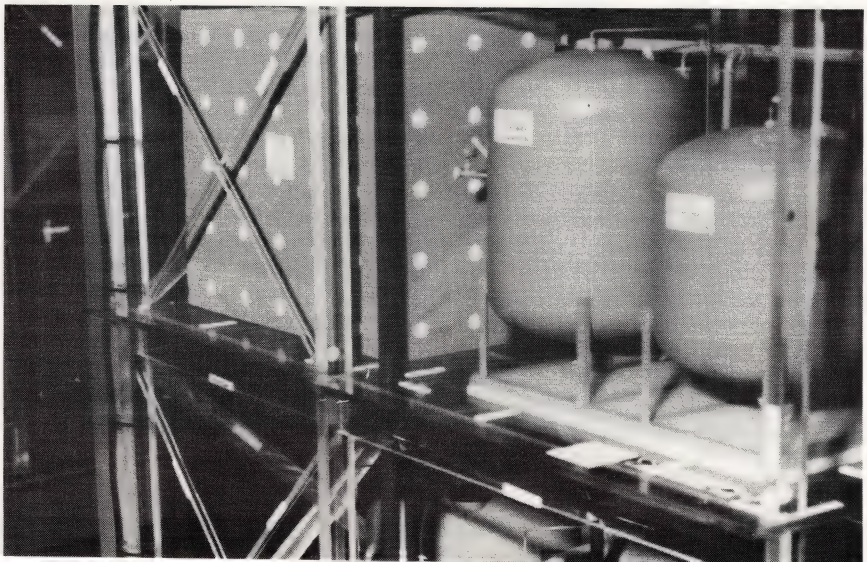
A 3/8-in.-scale definition model initially was prepared for most plant operating units, including the power plant, which consists of a boiler firing wood waste (bark), a chemical recovery boiler firing pulping residue, a cogeneration turbine/generator, and associated equipment.

Due to the economics of fuel available from the process and the steam require-

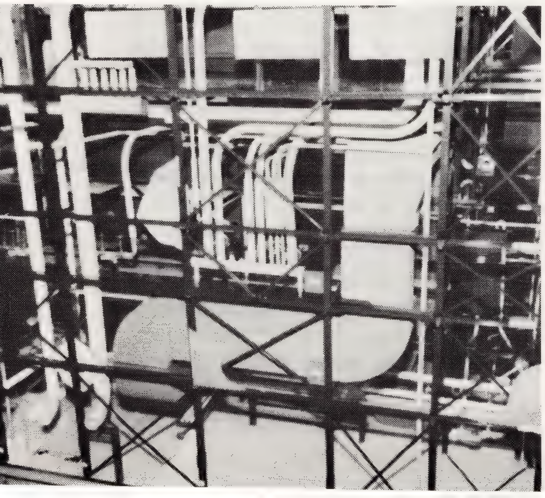


6. Water-treatment plant (left) is housed near bark boiler

7. Final model provides good detail (below). Note small-diameter piping around boiler feedwater-treatment equipment



5. Grouping of steam piping in west bay is adjacent to generator building



ments of the mill process, the power plant has been designed to produce about 97% of the mill's electrical requirements at the design-production level. A single-extraction, back-pressure turbine/generator produces 32.3 MW of power, with 175-psig extraction and 50-psig exhaust steam being supplied to meet process demands. Refer to the general layout of the power complex shown in Fig 1.

The definition model

In developing the definition model for the kraft pulp mill, the physical size of the chemical-recovery-boiler complex, its location, and its configuration (roughly four times the volume of the bark-boiler complex), were the primary determinants in the overall powerhouse layout (Fig 3). Placement of operating floor levels was developed with the boiler supplier and modeled. Major structural steel was shown, and major auxiliary equipment such as sootblowers, tanks, ducts, fans, etc, were modeled and located. Architectural items—that is, stairways and elevators—were then blocked in on the model.

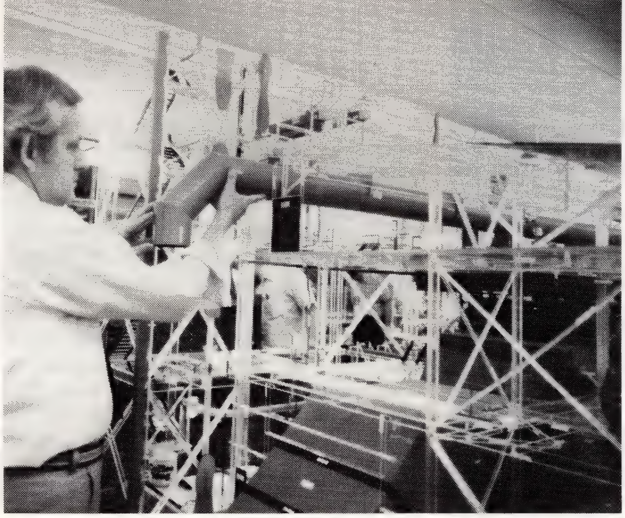
The physical size of the chemical-recovery boiler was determined so it would not operate below its minimum safe firing rate based on the current design level of the plant, and it would be capable of sustaining the maximum firing rate required if the plant is expanded.

The primary-air forced-draft fan on this boiler is sized so that it can be reused as the secondary/tertiary air fan if the boiler complex is expanded.

Once the general configuration of the recovery boiler was established, work began on locating the bark-fired-boiler and turbine/generator buildings. The bark boiler itself was modeled, and various arrangements were tried for the location of the mechanical dust collectors, preheaters, forced-draft (FD) and induced-draft (ID) fans, and associated ductwork.

Close coordination between client, engineer, and boiler supplier at this stage confirmed the general layout, and permitted the supplier to complete his initial set of engineering drawings based on the model layout. These drawings were not subject to major revision during the approval stage and therefore considerable time was saved.

During the development of the bark-boiler building, it was thought desirable to locate the main operating floors at the same level as the recovery-boiler floors and, if possible, to line up all upper level floors for minimum structural complexity and for maximum ease of construction. The model permitted a thorough check of bark-boiler penetrations, which indicated that this was practical with slight variations in the elevations of access doors, platforms, and similar items.



8. Engineer checks large duct run under bark boiler's sloping roof—the most direct route to stack, as model reveals

A review of the model was conducted with potential ash-handling vendors to check the space available for this equipment. Based on these reviews, the bark boiler could be released for design long before the ash-handling system was finalized.

Other options available around the bark boiler were reviewed by the project team. The model clearly showed that the highest sootblowers on the bark boiler were below the elevation of the lowest sootblowers on the recovery boiler. If one-sided retractable sootblowers could be used on the bark boiler, however, they could be extended into unoccupied space in a recovery-boiler bay reserved for its sootblowers. The bark-boiler vendor conferred with his sootblower supplier and approved the use of these sootblowers in a matter of days. By using the model and the one-sided sootblower layout, one bay originally planned for the bark-boiler building was eliminated at considerable cost savings.

A bay located to the east of the bark boiler provides space to house the feedwater-treatment system and the deaerating heater that serves both boilers and feedwater pumps (Fig 6).

Another advantage of the model is that critical space problems can be resolved more easily; for example, bark bin size and arrangement were optimized to include two bins with adequate total volume to give the needed residual time while using minimum building space. Another example: The bark boiler is two-thirds as tall as the recovery boiler and is covered with a sloping corrugated roof (Fig 3). Space under the sloping roof was used to accommodate major ductwork, which runs to the main boiler stack south of the complex (Fig 8). This location provided the most direct route available and saved considerable ductwork and supports.

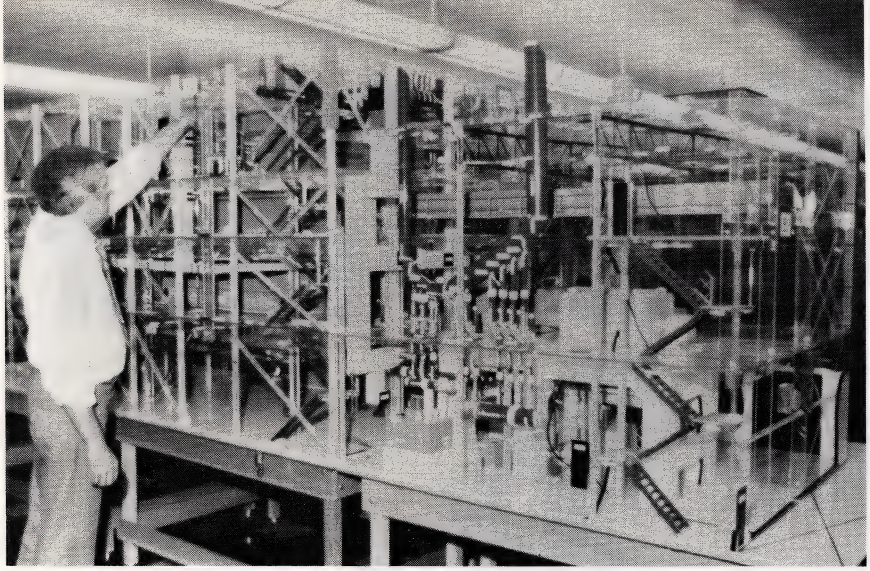
A review of the model by the engineering team indicated that the rearmost structural bay of the bark-boiler complex appeared to be unnecessary. The equipment in this area consisted of the air preheater, ID fan, and associated ductwork, all of which could be installed out-of-doors at little or no added cost for the equipment. A structural study was made and confirmed that the bay could be eliminated without affecting the structural integrity of the power complex. The results were savings in an exterior boilerhouse wall, floor, and roof. Also, access to the air preheater and ID fan and motor was improved, allowing mobile plant equipment for servicing, and eliminating the need for monorails.

The turbine/generator room is located at the west end of the recovery boiler (Fig 9). The turbine/generator and bridge crane are oriented so the crane rails can be extended if necessary. Note that all steam controls are located in one bay on the west side of the recovery-boiler building adjacent to the generator building (Fig 10).

A separate building at the front of (and integral with) the bark boiler, recovery boiler, and generator building provides space for electrical switchgear, motor-control centers, and miscellaneous equipment. Its upper floor corresponds to the elevation of the operating levels of both boilers, and is used for the main control room and office space for the power complex.

Actual construction work generally is a critical item on the construction schedule because of the trial chemical recovery boiler. With the model, however, engineers were able to identify structural requirements for the building early in the program, thus permitting the early commitment of structural-fabrication contracts and timely release of foundation information for civil work and pilings.

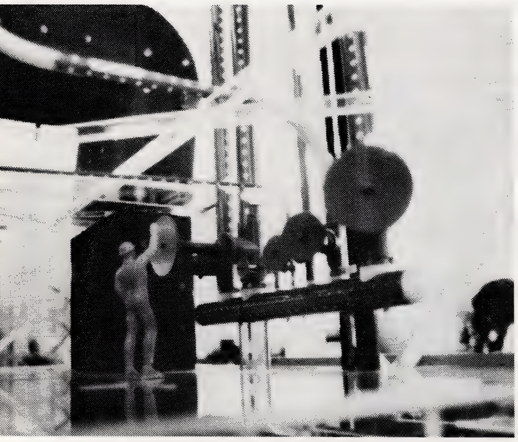
Structural design work on the model was continued on a progressive basis, with releases of steel to the fabricator timed sequentially to meet the construction schedule. At the same time, major equipment to be installed in the boiler complex—such as dissolving tank, venturi scrubber, fans, large ductwork sections, deaerating heater, and water-treat-



9. Firing level of chemical-recovery boiler is checked by design engineer. Turbine/generator building for pulp-and-paper mill is at right, bark boiler at left

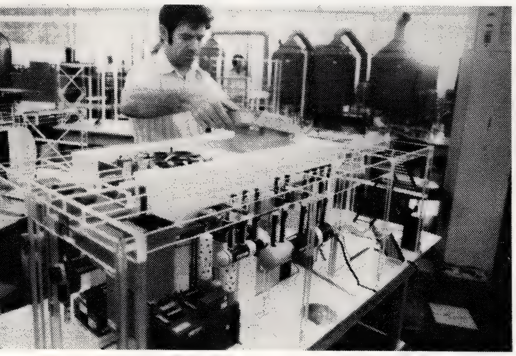
ment equipment—were scheduled to arrive in the field so they could be set in the boiler complex as the building steel was erected. This permitted an orderly, continuous flow of construction activities and reduced construction equipment and labor requirements.

Flooring requirements. After all major equipment was set on the definition model, and operating and maintenance requirements were known, a study of the flooring requirements was undertaken.



10. Steam controls and piping are located in one bay (above)

11. Modeler inserts lower section of generator into foundation (below)



Cost savings were realized by eliminating grating and/or concrete flooring where not required for operating and maintenance, or for structural design. Minimizing the concrete flooring also minimized the heating and ventilating scope of work.

Flue gas from the chemical recovery boiler is cleaned in a dry-bottom electrostatic precipitator designed for current production levels and to meet the new-source environmental limits. Flue-gas flow studies were conducted to confirm ductwork layouts prior to finalizing the design.

A single brick-lined concrete stack 350-ft tall is used to service both boilers and the calciner. The stack is provided with an acid-resistant lining in the lower section. The space between lining and concrete shell is pressurized to prevent acid attack on the concrete structure.

The final detail model

As work progressed on the definition model of the kraft pulp mill, specifications were prepared for the various equipment to be used in the power plant. Major equipment was purchased early in the program. While the definition model was being finalized, the balance of equipment for the power-generation complex was being purchased.

Final-model development follows the general layout approved on the definition model. Initial activity is the placement of structural steel. As Figs 5 and 7 show, clear plastic is used for structural-steel components in the ¾-in. final detail model. The plastic is strong enough to support the weight of the model, is sized to occupy the cross-sectional area of the structural members, and does not block the view of equipment on the model.

As vendor drawings of equipment become available, the modelers begin fabricating the major units. These are installed in the model as the structure and floors are being placed (Fig 11). Smaller pieces of equipment are being fabricated at the same time.

Equipment is installed on the model based on the initial layout developed by the definition model and is ready for piping. Piping is placed directly on the model following the piping and instrumentation diagrams and the piping runs established on the definition model. The work proceeds swiftly at this point as piping details such as valves and instrumentation are added.

Smaller pieces of equipment that were not shown on the definition model are added, and the optimization program of the equipment layout and piping runs continues.

A major cost advantage of the model occurs in the piping area. A technician using portable instruments can take piping data directly from the model (Fig 5). These data are recorded in a "brown box" and will be transferred directly to a computer for the preparation of isometric drawings.

Other activities performed on the ¾-in.-scale final model include:

- Location of electrical and instrumentation items.
- Relocation of some equipment from the definition model.
- Addition of smaller equipment not shown on the definition model.
- Equipment detailing.
- Location of heating and ventilation systems.
- Continued optimization.

To give the reader some insight into the total scope of the final model, it consists of the following:

Bark boiler: four model tables with 16 lift-off sections.

Recovery boiler: two model tables with 14 lift-off sections.

Turbine/generator: two model tables with two lift-off sections.

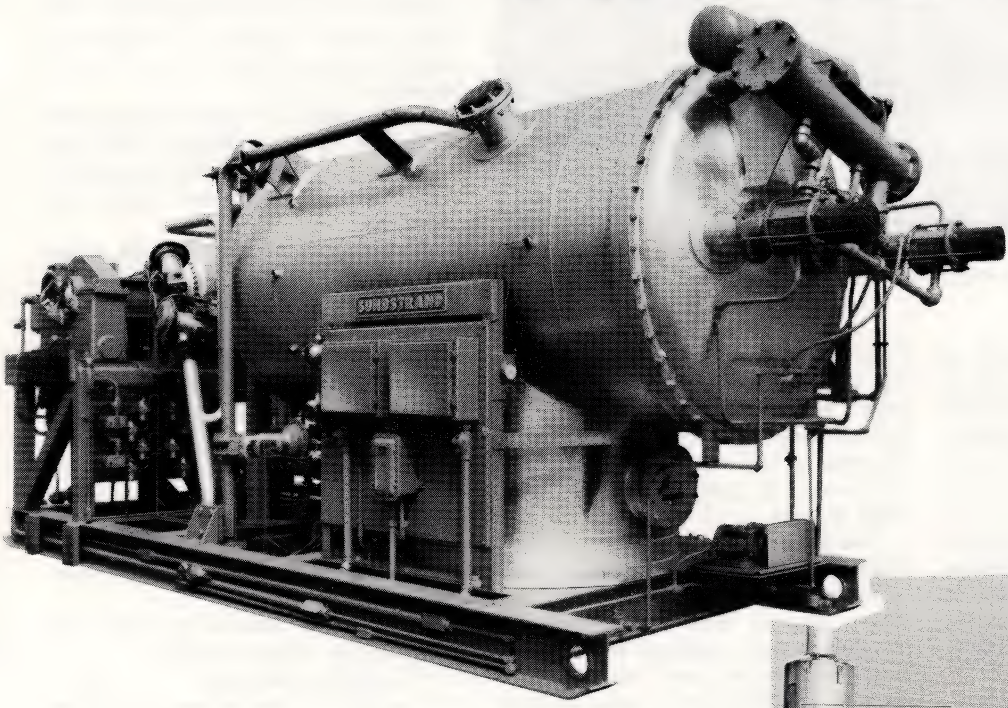
Control building: three model tables with six lift-off sections.

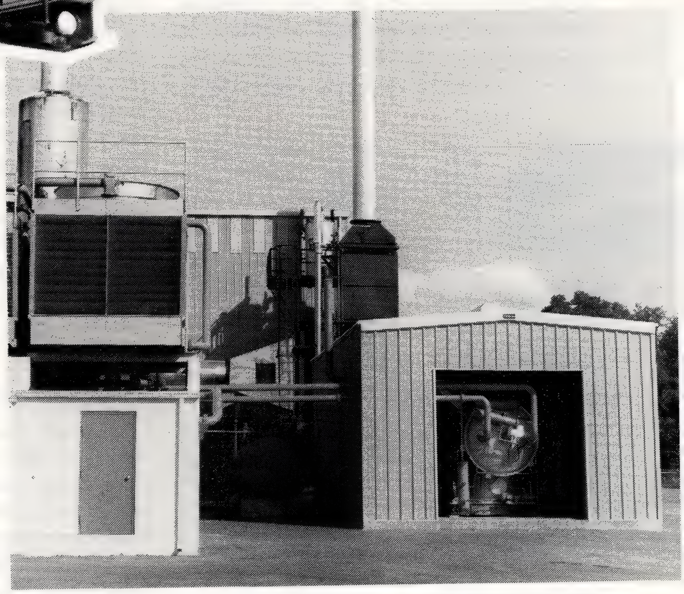
Miscellaneous: seven model tables with seven lift-off sections.

In conclusion, the benefits of scale modeling that have been proved on industrial process and manufacturing projects in the past 25 years are equally valid for industrial power plants. We are expecting an increased use of modeling on industrial power plants in the near future as our country shifts from oil and gas firing to the burning of coal, wood, and waste fuels.

Scale modeling of industrial power plants will prove even more beneficial in the future through the increased application of electronic devices to input computer data directly from the model, the increased use of modeling for structural and other design activity, and the use of closed-circuit TV to transmit data between engineering office and field prior to model shipment. ■

POWER from WASTE HEAT





Sundstrand's Waste Heat Recovery System uses energy in exhaust gases from industrial processes to generate electricity. Rated at 600 kW_e, the system consists of a Rankine cycle engine using an organic working fluid, a waste heat boiler, a generator and integral controls for totally automatic operation. Waste heat streams with temperatures above 600^0F and providing 10 million BTUs per hour are ideal inputs for system operation.

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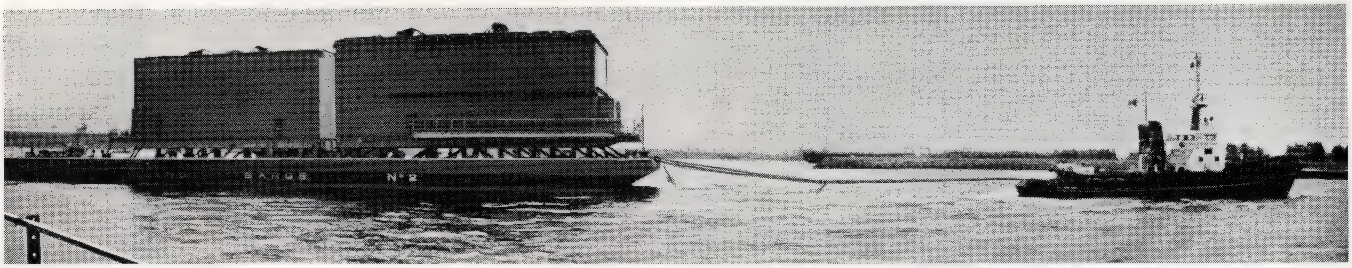

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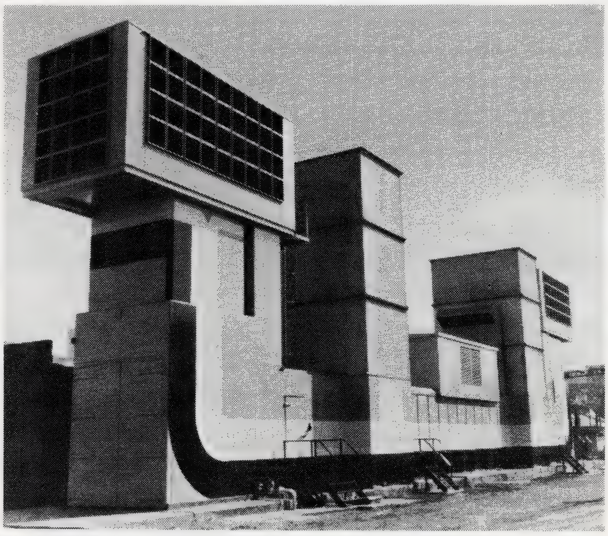

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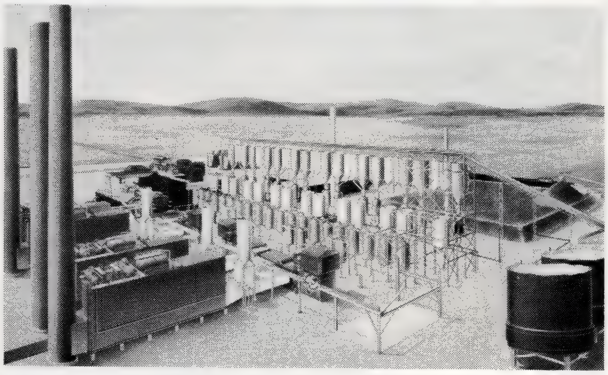

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DSC 8000 monitors and controls fuel delivery and ignition. Safety provisions include *Dynamic Safety Check*, which tests the integrity of all system inputs...and *Output Status Monitor*, which insures that all field devices are in the proper position or state, as directed.Total system performance is continually and dynamically monitored to insure the highest level of safety and operating integrity. DSC 8000 reliability is complemented by automatic on-line self-diagnostics which isolate potential system *or* field hardware faults to the loop or component level.

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TDC 2000 automatically optimizes fuel consumption by continuously monitoring and adjusting fuel-air ratios, regulating fuel firing and maintaining precision trim control of oxygen. Accurate repeatability assures maximum steam generating efficiency within safety and environmental compliance limits...whatever the fuel. You not only save on fuel, but on labor and costly downtime as well. Operators can understand and operate the system without extensive retraining.

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Honeywell's unmatched resources are part of the package. Everything from expert counsel in planning your system through field engineering support. We'll train your operators, handle installation or provide total project management through Honeywell's Energy and Engineering Services. The choice is yours.

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ALLOY	NOMINAL CHEMICAL COMPOSITION Ni	Cr	Fe	Si	Cu	Other	DESCRIPTION	APPLICATIONS	SPECIFICATIONS
he HEAT resistant alloys									
RA 333®	45	25	18	1.25	–	Mo:3 Co:3 W:3 C:0.05	A high strength nickel-base superalloy. Has high alloy content for superior heat & corrosion resistance.	Radiant tubes, heat treat fixtures, chemical & glass process equipment, petrochem furnace parts, hot turbine parts.	AMS 5593, 5717
RA 330®	35	19	43	1.25	–	C:0.05	An austenitic, non-hardenable heat and corrosion resistant alloy with excellent high temperature properties. 'TX' modification is for higher creep resistance. 'HC' has higher carbon for strength and abrasion resistance.	Heat exchangers, hot turbine parts, radiant tubes, furnace containers, fans & shafts, muffles, retorts, salt pots, quenching fixtures, conveyors, petrochem furnace parts.	AMS 5592, 5716 ASTM B-511, B-512, B-535, B-536, B-546 ASME SB-511, SB-535, SB-536
RA 330TX™	35	19	43	1.25	–	C:0.07			
RA 330-HC	35	19	43	1.25	–	C:0.40			
RA 309	14	23	60	–	–	C:0.05	Austenitic alloy, oxidation resistant in 1500-2000° F service. High chromium, relatively low nickel, for use in non-severe sulfurous atmospheres.	Annealing covers, anchor bolts, heat exchangers, combustion chambers, incinerators, lead & salt pots, muffles, radiant tubes, petrochem furnace parts, kilns.	AISI 309-S AMS 5523, 5650 ASTM A-240, A-312, A-358
RA 310	20	25	52	–	–	C:0.05	Austenitic alloy. Higher chromium & nickel for greater oxidation resistance to 2000° F. More resistant to cyclic temperature conditions.		AISI 310-S, AMS 5521, 5651 ASTM A-240, A-312, A-358
RA 800H	32.5	21	44	–	–	Al:0.38 Ti:0.38	An austenitic Ni-Fe-Cr alloy with excellent high temperature strength, oxidation resistant to 2000° F.	Petrochem furnace components, pigtails, process piping, steam generator tubing.	ASTM B-407 ASME SB-407
RA 446	–	25	73	–	–	N:0.15 C:0.10	High chromium ferritic alloys with low coefficients of expansion. Excellent oxidation and sulfidation resistance.	Recuperators, oil burner parts, combustion chambers, furnace & kiln linings, stack dampers, glass molds, neutral salt pot electrodes, copper spouts.	AISI 446 ASTM A-176
RA 26-1	0.20	26	70	0.30	–	Mo:1.0 N:0.03 C:0.02 Ti:0.5			ASTM A-176, A-240
he CORROSION resistant alloys									
Carpenter 20Cb–3®*	34	20	38	0.50	3.50	Mo:2.5 Cb + Ta: 0.5	THE stainless steel for acid corrosion environments. Resistant to intergranular corrosion (as welded). Resistant to chloride stress corrosion cracking.	Heat exchangers, bubble caps, process piping, mixing tanks, equipment for sulfuric acid pickling, flue gas scrubbing.	ASTM B-463, B-464, B-473 ASME SB-463, SB-464, SB-473
RA 200	99.5	–	0.20	0.20	0.10	C:0.08 S:0.005	A wrought commercially pure nickel. Excellent resistance to caustic corrosion, good thermal and electrical conductivity, large magnetostrictive effect. RA 201 has restricted carbon to resist embrittlement in service above 600° F.	Chemical containers, magnetostrictive devices, and equipment for caustic manufacture & storage, synthetic fiber production, fluorine electrolysis, food processing, chlorination.	ASTM B-162 ASME SB-162
RA 201	99.5	–	0.20	0.20	0.10	C:0.01 S:0.005			
RA 400	67	–	1.5	0.20	31	Mn:1.0 C:0.10 S:0.01	A nickel-copper alloy, resistant to a variety of corrosive environments. Good strength and toughness over a wide temperature range.	Distillation towers, marine, valve & pump parts, equipment for chem. processing, hydrofluoric acid, caustics.	AMS 4544 ASTM B-127 ASME SB-127
RA 600	76	15.5	8	0.20	0.20	C:0.08 S:0.008	A nickel-chromium alloy, resistant to corrosive environments at elevated temperatures. Good oxidation resistance to 2000° F.	Heat exchangers, vegetable & fatty acid digesters, equipment for chem., food, paper, heat treat. processing.	AMS 5540 ASTM B-168 ASME SB-168

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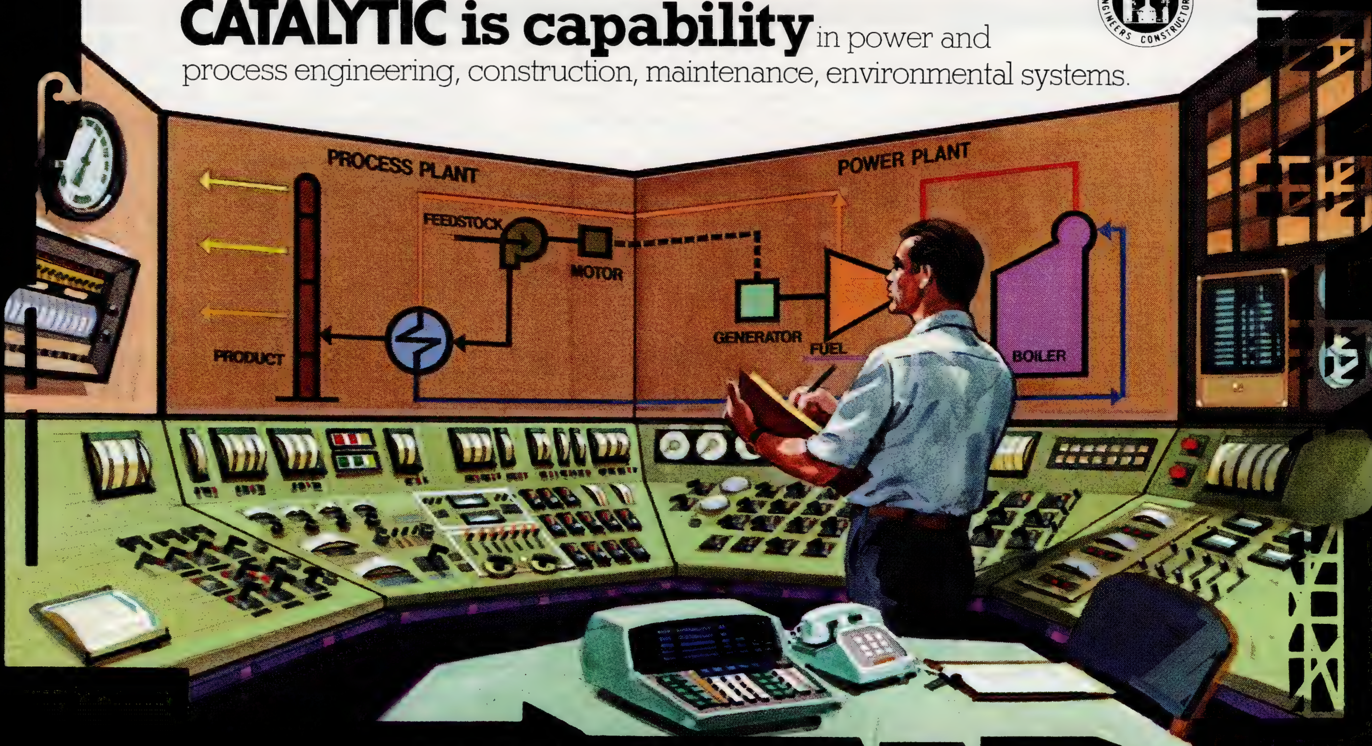


CIRCLE 24 ON READER SERVICE CARD

PACESETTER PLANTS

Industrial FBC is taking shape

A fluidized-bed combustion unit at Georgetown University is demonstrating reliable, esthetic, and efficient operation in an urban environment

By S D Strauss, Senior Editor

Coal combustion in a fluidized bed (FBC) is expected to play a major role in returning to the use of solid fuel in an environmentally acceptable manner at attractive operating cost. While the well-known FBC unit at Monongahela Power Co's Rivesville station in West Virginia is demonstrating the application to utility central stations, its industrial counterpart is providing heating and cooling for Georgetown University—with potential for cogeneration.

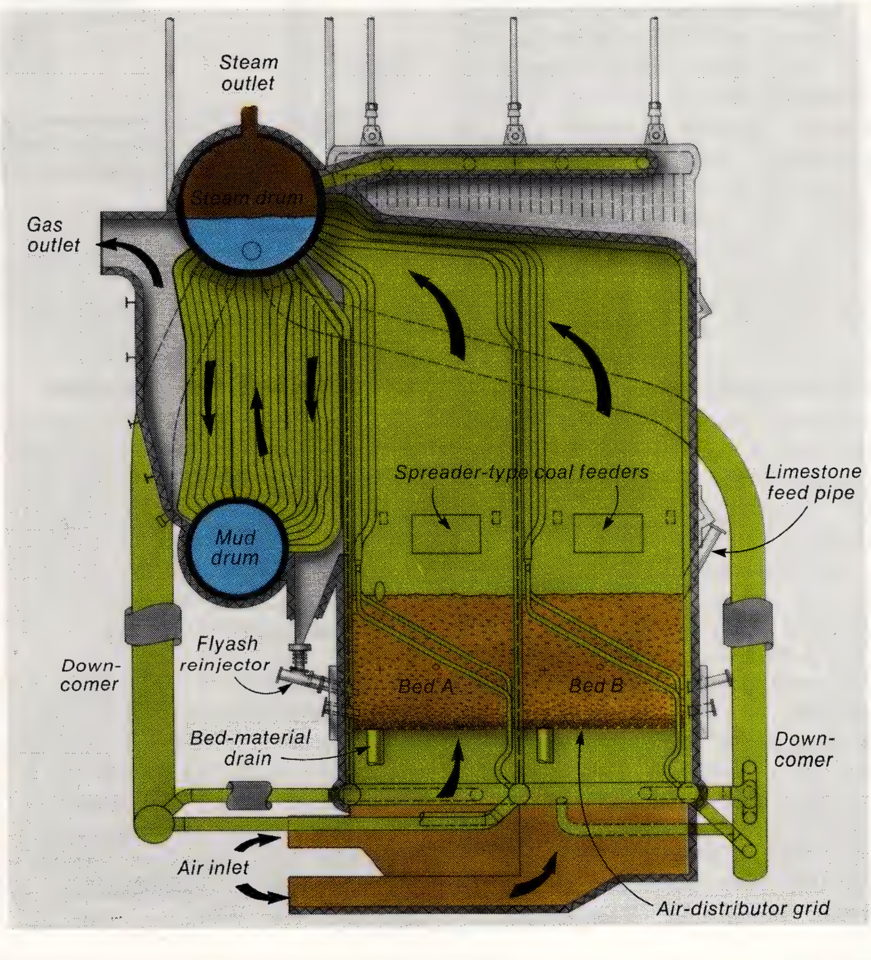
The system is designed to generate 100,000 lb/hr of saturated steam, and was developed under DOE sponsorship by Fluidized Combustion Co. The latter is a partnership of Foster Wheeler Corp and Pope, Evans & Robbins, respective designers and constructors of the boiler and the balance of plant. Stated purpose of the program is to demonstrate institutional application of fluidized-bed combustion by burning high-sulfur coal in a populated area, with minimal effect on the environment.

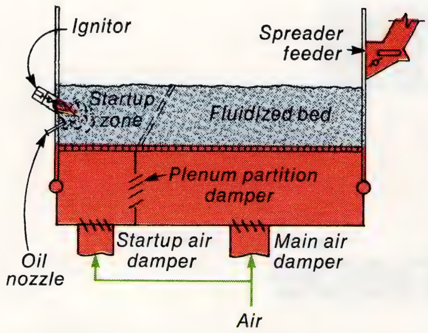
The steam-generator is designed for simple, reliable operation, with minimum operator attention and maintenance. These goals dictated natural circulation, overbed fuel feed, and flyash reinjection to enhance efficiency. Injection is done directly into one of the beds, avoiding the carbon-burnup cell incorporated at Rivesville. Operating pressure is set at 275 psi to meet the university's needs. However, capability up to 625 psi has been designed into the unit to allow for cogeneration of steam and electricity in the future. Arrangement of beds and steam generator are shown in Fig 1.

The unit contains two independently fired beds, each 5½ ft deep with a 106-ft plan area. Operating conditions at full load are 1600F at 8-ft/sec fluidizing velocity. The natural-circulation flow path includes four downcomers supplying the lower headers, and sloped risers positioned in the bed. The tandem-bed arrangement provides a 4:1 load turndown, for efficient operation under varying load requirements.

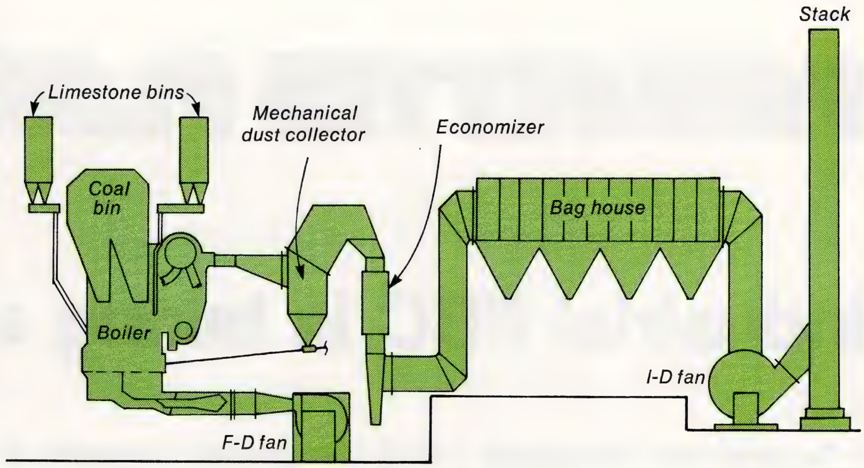
About 95% of the bed material consists of limestone products during operation. The balance is coal, sized to 1¼ in. maximum and injected with overbed spreader feeders; fines are minimized by means of a gyratory screen upstream of the crusher.

1. Steam generator features natural circulation, produces 100,000 lb/hr saturated steam at 275 psi, with capability for 625 psi to permit cogeneration of electricity

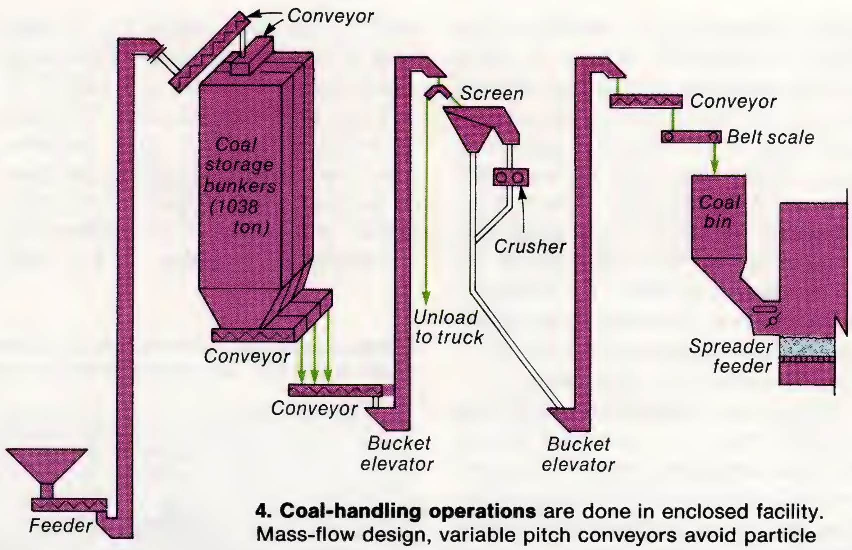




2. Startup zone in bed A is preheated by ignition burner to initiate lightoff process



3. Forced-draft air flow moves combustion air through the fluidized beds. ID fan draws flue gases through the boiler bank, dust collector, economizer, and baghouse collector



4. Coal-handling operations are done in enclosed facility. Mass-flow design, variable pitch conveyors avoid particle segregation; spreader feeders distribute fuel evenly over beds

To reduce burning and SO_2 emissions, the feeders are fitted with spray nozzles. A small amount of water can be sprayed on the coal if received with excessive dry fines. Limestone is fed at the surface of each bed.

Slag formation is prevented by operating the beds at 1600F, well below the ash-softening temperature of the fuel. Combustion insensitivity to fuel-ash characteristics allows wide latitude in coal procurement. Absence of slag and ash deposits allows for elimination of sootblowers from the facility.

Light-off is achieved by preheating a startup zone within each bed (Fig 2). This is done with an independent 4-million Btu/hr oil-fired ignition burner, located between the air distributor and the in-bed tubes. When the zone temperature reaches 500F, the zone is fluidized by a startup damper, and a measured charge of coal is fed into the zone by the spreader feeder. When the zone is stabilized at 1400F-1600F, the rest of the bed is fluidized and coal feed is initiated. When combustion is stabilized in the bed, the plenum partition is opened and the startup damper closed, permitting control of the fluidizing air for both beds through a single damper.

An alternative for lighting off the second bed is by transfer of hot material from the first bed. To do this, a damper located in the partition wall can be opened, allowing blending of the two bed materials. Making bed A deeper than B ensures the flow of material. This technique has been used successfully at Rivesville. Bed A, designated the preferential bed, is always started up first and shut down last to provide for the flyash reinjection. The flyash is collected up stream of the boiler bank in an internal cinder trap and down stream in a mechanical cyclone, and injected pneumatically.

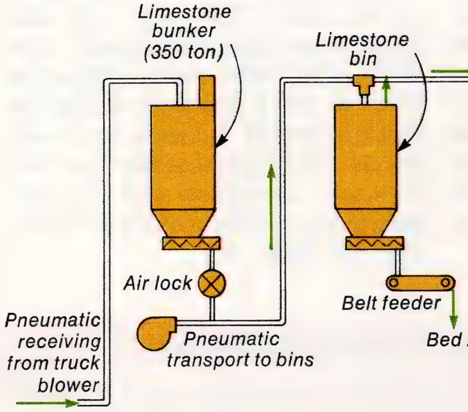
How emissions are controlled

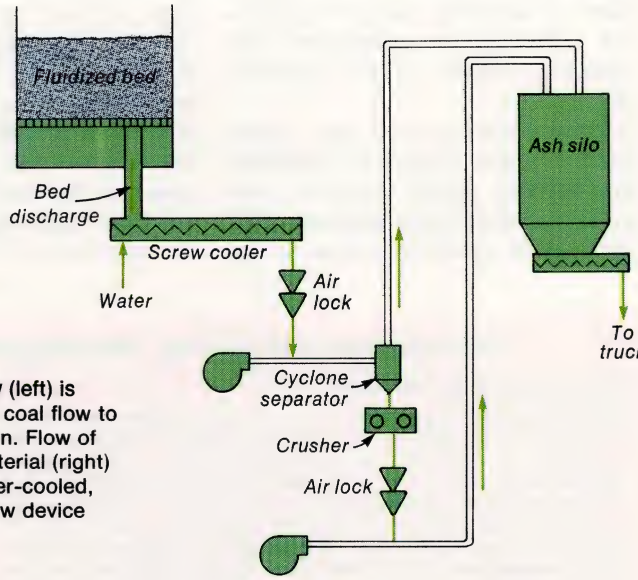
Raw, crushed limestone is fed to the bed to keep SO_2 emissions within limits set by both EPA and the District of Columbia. At normal operating temperatures, it calcines to lime, which absorbs SO_2 released during combustion. Gypsum forms on the bed-particle surfaces in the process.

Sulfur capture is maintained by feeding fresh limestone continuously; bed material is withdrawn through an opening in the air distributor to maintain the proper bed inventory. The relatively low bed temperature minimizes NO_x emissions. Particulate emission is controlled by a baghouse dust collector. This approach was selected over an electrostatic precipitator (ESP) because removal of the SO_2—which conditions the particulates' electrical characteristics—raised doubts about the efficiency of collection by ESP.

The overall arrangement is shown in Fig 3. The facility is designed for balanced-draft operation. Combustion air is moved by forced-draft fans through the air-distributor system up through the beds, controlled by dampers at the inlet of the steam-generator plenum. An induced-draft fan provides suction to draw flue gases through the boiler bank, mechanical dust collector, economizer, and baghouse before discharge to the stack.

The coal-handling system is completely enclosed (Fig 4). Coal is delivered in covered trucks, and unloaded inside the facility where it is moved vertically due to space limi-





5,6. Limestone flow (left) is adjusted relative to coal flow to control SO_2 emission. Flow of discharged bed material (right) is regulated by water-cooled, variable-speed screw device

tations. From the receiving hopper, the coal is raised by bucket elevator to storage bunkers (nine-day capacity). The bunkers are designed for mass flow to prevent particles from segregating by size. A variable-pitch conveyor removes the coal, which is raised by a second elevator and passed over a screen; oversize particles are routed through a crusher, then remixed with the screened coal, and finally raised by a third elevator to a coal bin adjacent to the steam generator. A belt scale at the bin inlet integrates the coal feed.

The bin discharges to two spreader feeders, which regulate the flow to each bed. Similar to the type used in spreader stoker boilers, the feeders are located about two feet above the expanded height of the fluidized bed, and are adjustable to provide uniform fuel distribution.

Limestone handling is depicted in Fig 5. The limestone is received in pneumatic discharge-type trucks, and is blown into its bunker by the truck's discharge blowers. The bunker can store 10-days' supply at full-load operation and, like the coal bunkers, is designed for mass flow. Limestone removed by the bunker-discharge screw is conveyed pneumatically to two storage bins. Discharged material is measured by belt scales, and falls by gravity into each of the fluidized beds. Entry into the steam generator is through the sidewalls, just above the bed level (Fig 1). Limestone flow is adjusted by the automatic-control system to control SO_2 emissions.

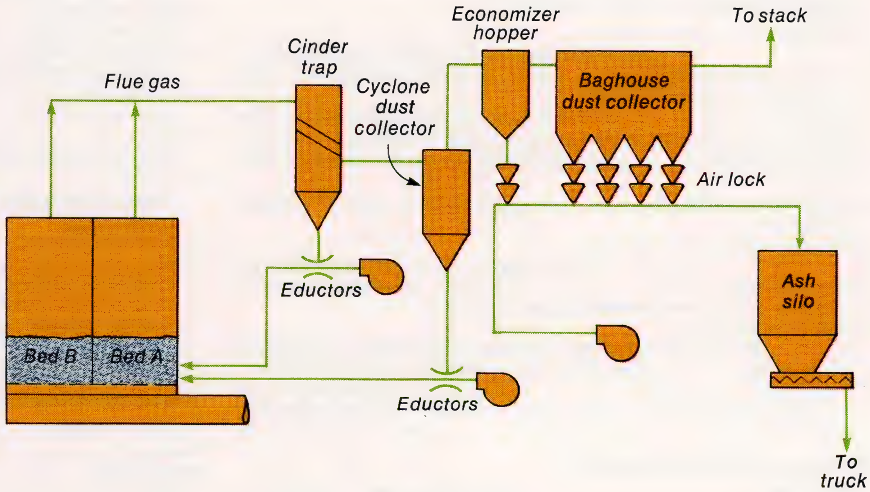
Handling bed material, flyash

The bed material discharges through a 6-in. pipe that penetrates the air plenum and distributor vertically. Flow rate of the discharge from each bed is controlled by a variable-speed screw. The screw is cooled indirectly by water to reduce the temperature of the discharged material to about 300F (Fig 6). The finer material is conveyed pneumatically to an ash silo, with the rejects going to a crusher. The crusher is provided to break up the rejects so as to expose any unreacted calcium oxide contained in the particle cores. The purpose is to increase the particle reactivity for byproduct-sale possibility in a related DOE program. The crushed material is then conveyed to the silo.

Flyash from the beds is removed from the flue gas by a cinder trap and reinjected into bed A (Fig 7). The trap is a simple arrangement featuring a series of down-sloping channels. These change the direction of gas flow to separate the particles, which fall into the recycle ash hopper. Because the trap's effectiveness in fluidized-bed systems is unproven, a cyclone dust collector is added as backup to ensure sufficient particle recycle for the desired combustion efficiency. If the action of the trap proves satisfactory, the unit can be modified to transfer particles from the mechanical dust collector to the ash silo.

Particles not removed in the cyclone collector pass over the economizer to the high-efficiency bag-

7. Cinder trap ahead of boiler bank and down-stream mechanical collector remove flyash from flue gas for reinjection into bed. Recycle enhances combustion efficiency



house dust collector. Dust removed there is conveyed pneumatically to the ash silo, for subsequent discharge to trucks in the receiving bay.

Combustion controls and safety interlocks are typical of industrial coal-burning plants. Load is controlled automatically between 25% and 100%; operator action is required only at about 50% load to light off bed B or shut it down. A safety system automatically trips the fuel feed if a critical component malfunctions or bed temperature cannot be maintained. Gas analysis for oxygen, SO_2, NO_x, and CO is provided for each bed and tied in with the combustion-control system for regulation of limestone feed.

Opacity is monitored continuously at the stack. The plant will shut down when opacity exceeds local limits. Coal fines are minimized in order to avoid problems during the break-in period, which is just nearing its end. Typical stoker coal will be used thereafter, and 2½-year period of a closely monitored operation will follow. ■

Georgetown University, Washington, DC: Principal retrofit equipment

Steam generator and auxiliaries

Fluidized-bed steam generator, 1 .... Foster Wheeler Energy Corp
100,000 lb/hr at 275 and 625 psig, two beds, 4477 sq ft of boiler convection surface, 2376 sq ft of freeboard-zone furnace surface (above bed), 1014 sq ft of fluidized-bed surface, 8-ft minimum freeboard height, 4.5-ft expanded bed height, each bed 5.5 ft wide × 19.3 ft deep, 2654 cu ft of furnace volume (bed and freeboard), 1600F flue gas in bed, 1150F flue gas leaving freeboard (furnace), 753F flue gas leaving boiler bank, 400F flue gas leaving economizer, 22% excess air leaving boiler, 0.1-in.H_2O furnace draft, 4.7-in.-H_2O gas-side loss through boiler and cinder trap, 2.4-in.H_2O gas-side loss through economizer, 0.7-in.-H_2O gas-side loss through flue, 9-in.-H_2O gas-side loss through dust collector, 1-in.-H_2O air-side loss through ducts, 56.3-in.-H_2O air-side loss through grid and bed, 4-in.-H_2O air-side loss through dampers, 8-ft/sec fluidizing gas velocity, 9565-lb/hr coal consumption, 3133-lb/hr limestone consumption, 83.51% boiler thermal efficiency (Heat losses are these: dry gas (net), 7.21%; hydrogen and moisture in fuel and limestone, 4.62%; moisture in air, 0.17%; unburned combustibles, 3.07% radiation, 0.47%; unaccounted for and manufacturer's margin, 0.5%; solids net heat losses, 1.2%; forced-draft fan power credit, −0.75%.)

Spreader feeders, 2 .... Detroit Stoker Co
Each capable of feeding up to 9000 lb/hr of coal and limestone to the steam generator

Economizer.......... Tranter Inc, Kentube Div
Extended-surface type, 4185-sq ft surface area, 228F inlet feedwater, 336F outlet feedwater, 8.1-psi pressure drop from economizer inlet to steam drum

Ignition burners.......... Trane Thermal Co
Each rated 4-million Btu/hr, No. 2 oil, dilution air lowers flame temperature from 3500 to 2400F

Forced-draft fan, 1 .... Zurn Industries Inc, Air Systems Div
23,330 cfm of 80F air at 63 in. H_2O; 600-hp, 460-V, three-phase motor drive (Emerson Electric Co, US Electrical Motors Div)

Air-flow control dampers, 4 .... American Warming & Ventilating Inc
Each opposed-louvre type

Induced-draft fan, 1 .... Zurn Industries Inc, Air Systems Div
44,431 cfm of 400F flue gas at 21 in. H_2O; 350-hp, 460-V, three-phase motor drive (Emerson Electric Co, US Electrical Motors Div)

Boiler-feed pumps, 2 .... American Marsh Pumps Inc
Each 210 gpm, one turbine driven, one motor driven

Fluidized-bed ash-removal system

Bed-drain screw coolers, 2. . . .
. . . .Joy Manufacturing Co, Denver Equipment Div
Watercooled, variable-speed, twin-screw type; bed material enters at 1600F and leaves at 250F

Air locks, 3 .... US Filter Corp, Ducon Fluid Transport Div
Each 3-cu ft capacity, seals against 15 psig, 60-cfm maximum loss

Cyclone separator, 1.......... US Filter Corp, Ducon Fluid Transport Div
10 cu ft

Bed-material crusher, 1 .... Williams Patent Crusher & Pulverizer
2 tons/hr

Solids-removal-system controls. . . .
. . . .US Filter Corp, Ducon Fluid Transport Div

Screw conveyor, 1.......... Thomas & Muller Co
Variable-pitch, variable-speed type, 60 tons/hr

Pressure blowers, 2. . . .
. . . .Wallace Murray Corp, Schwitzer Engineered Components
Each 20 hp, one required for normal operation, one on standby

Fabric filter, 1 .... Flex-Kleen Corp
480-sq ft surface area, Nomex bags, filters air from both ash silos

Fabric-filter blower, 1 .... New York Blower Co

Environmental-control system

Fabric filter, 1 .... Enviro-Systems Research Inc
37 ft long × 10 ft wide, handles 119,225 lb/hr of 400F flue gas, 22 cells, 36 Teflon bags/cell, 413-sq ft surface area per cell

Mechanical collector, 1 .... Neptune-Airpol Inc
Multicyclone type, five hoppers, removes 11,948 lb/hr of flyash from 119,225 lb/hr of 785F flue gas

Chimney, 1 .... Air Management Inc
Insulated, double-steel-wall type; 110F maximum exterior temperature

Gas-analysis system .... Beckman Instruments Inc
Consists of oxygen, carbon-monoxide, and sulfur-dioxide monitors

Flyash-handling system

Eductor venturis, 5 .... Allen-Sherman-Hoff Co
All serve steam-generator cinder trap, each 2000 lb/hr; 110-cfm, 16-psig transport air

Screw conveyor, 1.......... Thomas & Muller Co
Variable-pitch, variable-speed type; 60 tons/hr

Airlocks, 5 .... US Filter Corp, Ducon Fluid Transport Div
Each serves one hopper on mechanical collector, 3-cu ft capacity, seals against 15 psig, 60-cfm maximum loss

Pressure blowers, 5. . . .
. . . Wallace Murray Corp, Schwitzer Engineered Components
Three serve mechanical-collector eductor venturis (one is on standby), two serve economizer and baghouse hoppers

Eductor venturis, 5 .... US Filter Corp, Ducon Fluid Transport Div
Each serves one hopper on mechanical collector, 1500 lb/hr

Compressed-air system

Service air compressor, 1.......... Kellogg-American Inc
99 scfm at 45 psig, 25-hp motor drive

Instrument air compressor, 1 .... Corken International Corp
20 scfm at 60 psig, 5-hp motor drive

Coal-handling system

Coal bunkers, 3.......... A A Beiro Construction Co
Each 346-ton capacity

Coal bins, 2 .... J E Hurley Machine & Boiler Works
Each 20-ton capacity

Screw conveyors, 8.......... Thomas & Muller Co
All variable-pitch, variable-speed type, two rated 60 tons/hr, six rated 15 tons/hr

Bucket elevators, 3 .... FMC Corp, MHS Div
One rated 60 tons/hr, two rated 15 tons/hr

Redler conveyors, 2 .... Stephens-Adamson Inc
One rated 60 tons/hr, one rated 15 tons/hr

Coal-sizing screen, 1.......... Rotex Inc
Diverts coal lumps larger than 1 in. to crusher, 15 tons/hr

Coal crusher, 1 .... Pennsylvania Crusher Corp
Ring type, 10 tons/hr

Scale, 1 .... Merrick Scale Manufacturing Corp
Weigh-belt type, 0-30,000 lb/hr, 0.5% accuracy

Fabric filter, 1 .... Flex-Kleen Corp
Filters air from coal bunkers and bins, 3486-sq ft surface area, 16-oz Dacron bags

Fabric-filter blower, 1 .... New York Blower Co

Coal .... Supplier not specified
Eastern bituminous, 12,750 Btu/lb, 1 in. × ¼. Proximate analysis: moisture, 5% volatile matter, 38.93%; fixed carbon, 48.1%; ash, 7.97%. Ultimate analysis: ash, 7.97%; sulfur, 3.29%; hydrogen, 4.94%; carbon, 70.24%; moisture, 5%; nitrogen, 1.24%; oxygen, 7.32%

Limestone-handling system

Screw conveyors, 3.......... Thomas & Muller Co

Scales, 2 .... Merrick Scale Manufacturing Co

Fabric filter, 1 .... Flex-Kleen Corp

Rotary air lock, 1.......... US Filter Corp, Ducon Fluid Transport Div

Afterburner system puts heat of waste gas and liquids into coke-plant steam supply

A 75% cut in purchases of natural gas is the main target of this FMC Corp project, now in operation. Zero discharge of contaminated water is a secondary and important benefit

The world's largest formcoke plant, in Kemmerer, Wyo, now includes energy-conservation equipment designed to reduce consumption of purchased natural gas while simultaneously cutting pollution. The plant, which went commercial in 1971 and into high output about two years later, supplies 90,000 tons/year of coke briquettes to an FMC phosphorus plant at Pocatello, Idaho. Because additional future markets will be in steel and other industries, improvements aimed at reducing costs, lowering pollution, and making the process location less dependent on purchased fuel are worthwhile—worthwhile enough to justify spending of $4.5-million to develop the afterburner (Figs 1,2) and heat-recovery system that is now doing an outstanding job for the plant.

An underlying principle of the process is that the binder for the coke comes wholly (as at Kemmerer) or in large part (as envisioned for some types of coal) from the coal feed to the process. In spite of this, offgases from several of the stages contain liquids and solids. Although cyclones, scrubbers, baghouses, driers, and decanters remove quantities of these potential fuel sources and pollutants, eventually returning them to process, a considerable fraction must go either to combustion or directly to the environment.

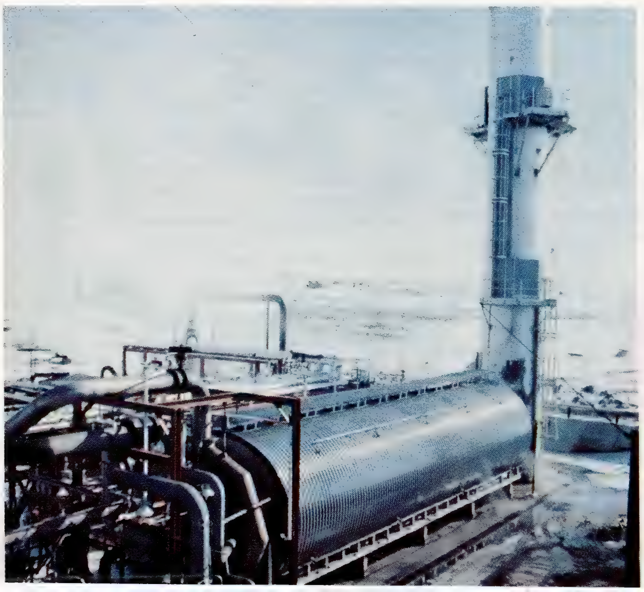
In regard to aqueous discharge, the Kemmerer plant has no National Pollutant Discharge Elimination System (NPDES) permit, so zero discharge is necessary. At one time, a pond holding contaminated water had grown to 22 acres; this has been cut down considerably since the new add-on went into service. Further shrinkage is expected, as evaporation and solids combustion continue.

Before the new energy-conservation system came on line in 1979, about 11,000 therms/day of purchased natural gas supplied that portion of energy needs not covered by burning part of the coal or char. This natural gas went to produce steam chiefly for coal drying, coke curing and drying, and heating of office buildings. Steam tracing of piping and drying of wet tar were other uses. Steam drying was the largest consumer, taking about two-thirds. Steam pressures run as high as 450 psig, so recovery equipment must be capable of this.

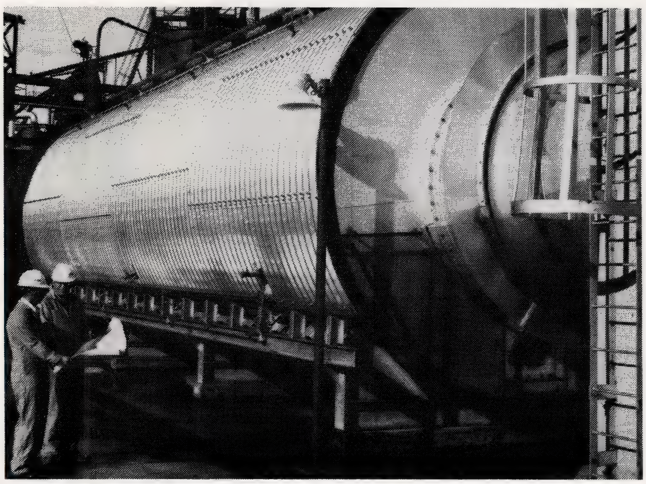
The new system cannot supply all this steam and heating requirement, because pilot lights on the afterburners must still burn natural gas, and there are a few other end uses for natural gas. Consumption has been cut from 11,000 therms/day to about 3,000, however, and the plant is optimistic that some additional reduction is possible.

The energy-conservation system was not the first in a continuing improvement program that has put much new equipment into the plant. An extensive range of dust collectors, covered conveyors, baghouses, and other particulate-collecting devices to prevent release to atmosphere has come on line during the past four years.

1. Horizontal afterburner functions as incinerator and supplier of heat to the nearby energy-recovery equipment



2. Emission-control task of afterburner is a must, to eliminate release of pollutants to plant area and environment



Heat going up the stack was recognized early as a conservation target, and reclamation possibilities became the subject of a two-year study starting in 1975. Several alternative methods got scrutiny before FMC, working with Ford, Bacon & Davis Inc, made the decision.

An afterburner was to burn waste gas, liquid, and solid fines. Combustion products, which average 2000F in the afterburner, were to go to a waste-heat exchanger, watertube type, to produce steam. Exhaust was to be through a stack, with some of the inert gas recovered for recycle in process. This is a condensed description of the installed system, but the many factors in the specific situation at Kemmerer had to get close attention to assure a best fit of system to the existing process and environmental requirements.

Remember that any add-on must be able to take care of possible variations in raw coal. FMC expects its coke process to work on coals varying all the way from lignite to anthracite. Amounts of additives and waste products, of course, can vary. With the present coal, having an analysis of:

	Dry	Wet (as received)
Fixed carbon	52.8	44.5
Sulfur	1.0	0.8
Ash	4.7	3.7
Volatile matter	42.5	33.3
Moisture	—	21.5

and gross heating value of 10,000 Btu/lb, about 2.35 tons of coal are needed per ton of coke. This means considerable change is possible in waste products.

Fuel input to the afterburner (Fig 4) is either directly from a process vessel or indirectly through a cleanup device. Leading off as a source is the catalyzer. Its offgases contain coal fines, and go through internal and external cyclones and a condenser-scrubber before combustion.

In the high-temperature carbonizer, whose fluidizing gas is air, steam, and combustion products, the tar and gas go overhead to an internal cyclone and to a quenching section with venturi scrubber. Tar separates in a second scrubber. Waste gas goes to the afterburner, as does an aqueous stream bled from the scrubbing system, which contains tar.

The calciner, at 1500F, releases the remaining volatiles in the char, chiefly as methane, carbon monoxide, carbon dioxide, and hydrogen. Three cyclones in series, one internal and two external, clean up the hot gas and dust from the vessel. Residual gas (1 atm, 60F, 150 Btu/cu ft) goes to the afterburner, too, where it incinerates emissions from the catalyzer and carbonizer.

The cooler fluidizing gases vent through the storage-silo baghouse. Material proceeding to the storage silo after collection under negative pressure passes through a cyclone and goes to the afterburner, too. The curing oven is also a source of matter to be burned, but not in the energy-conservation system. Some of the evolved volatile material supplies heat to the process; the excess goes to the back-end afterburner for incineration.

Aqueous discharges from the carbonizer are another source of fuel for the energy-conservation afterburner. Light oils and water that are evaporated during tar blowing condense

Process produces coke continuously in atmosphere-isolated reactions

For better understanding of the energy-conservation project at Kemmerer, here is a brief summary of the process details bearing on the heat-recovery and pollution-control work:

Basic intent is to obtain a strong metallurgical coke from local subbituminous Wyoming coals. Unlike conventional coke-oven batteries, which operate cyclically, the FMC coke process is continuous, running around the clock except for repair downtime. In 1978, on-stream time exceeded 90%. This calls for high reliability and availability of the afterburner and waste-heat recovery equipment.

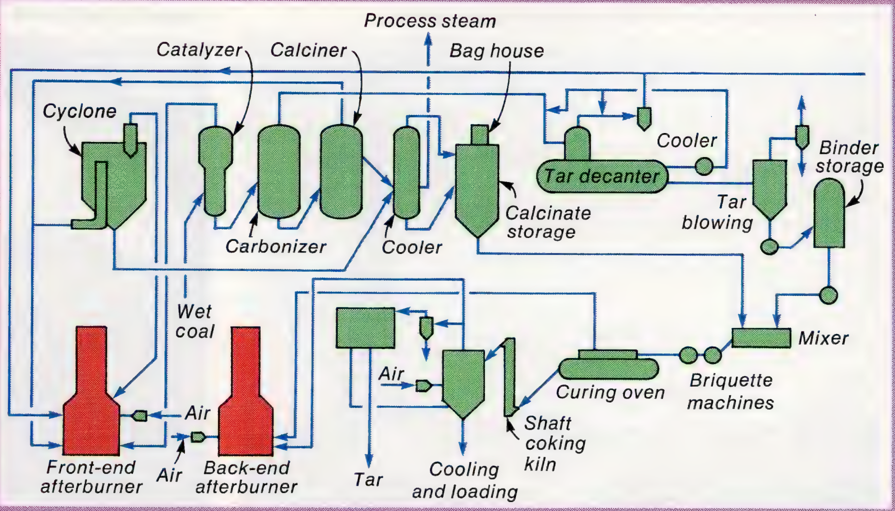
All coal processing occurs in fluidized-bed reaction vessels isolated from the atmosphere. The coal in process does not contact the atmosphere until it goes, as cooled product, to the storage silo. Therefore, elimination of typical coke-oven gaseous, liquid, and fine-particulate components must receive suitable attention. Although it is characteristic of the process that coal is the only raw material fed, nevertheless not all the coal constituents stay with the coke as binder.

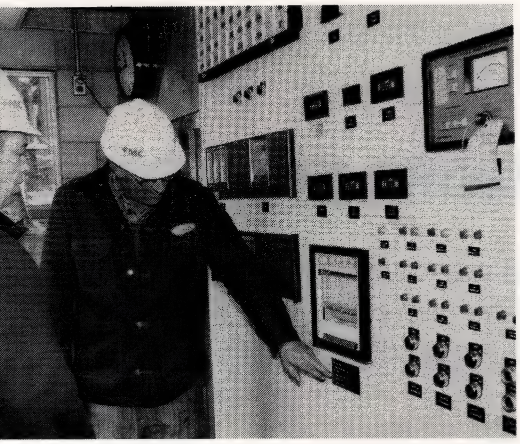
Follow the flow sequence (right) to identify sources of the combustibles reaching the afterburner and available for energy salvage.

Crushed coal goes to the fluidized-bed catalyzer, heated to 350F by steam. A small amount of air is added to the steam fluidizing medium. Catalyzer offgases, containing coal fines, must go through cyclones and a condenser/scrubber before reaching the afterburner. The conditioned coal itself moves to the carbonizer. Air oxidation of part of the coal heats it to 900F, breaking it down into gases, water, tar, and char.

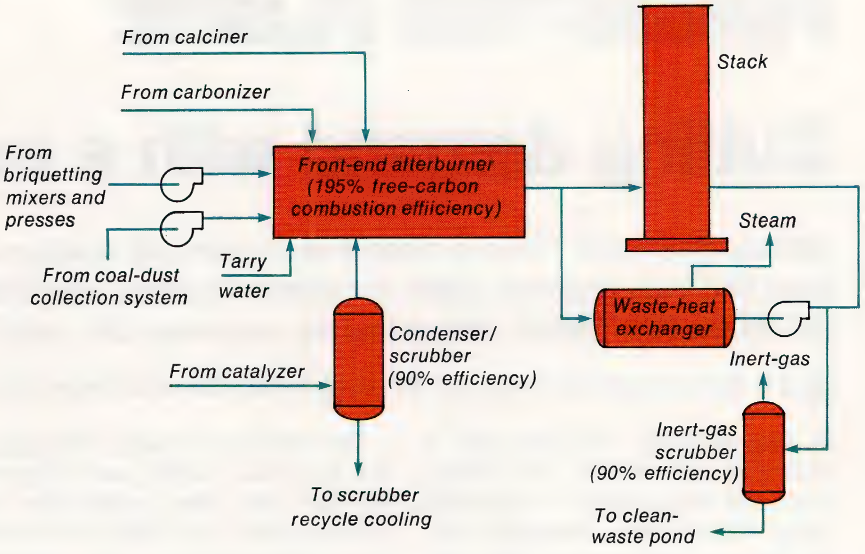
Partly devolatilized char goes to the calciner, where the fluidized-bed temperature is about 1500F, releasing the remaining volatiles. Combustion of a small fraction of the char supplies the necessary heat for the process.

Hot calcinate then passes to cooling, after which the calcinate (catalyzed coal and char) goes by pneumatic transport to a storage silo. Later operations combine the calcinate with dehydrated tar to form briquettes, which are cured in a 450F oven. Coking, which evolves some tar, comes next, followed by transport to another silo.





3-4. Controls of waste-heat system (above) allow operators to monitor from control room. Fuel flow to afterburner (right) includes liquids and particles



and are burned. Air emissions from the coal-preparation section also supply combustibles, and the emissions from the briquetting room pass through cyclone separators before burning.

Overall, the FMC coke process produces a byproduct fuel gas. Even though its heating value (about 165 Btu/cu ft on a dry basis) is less than that from a conventional coke-oven battery, the equivalent of 5-million to 6-million Btu/ton of coke is still available for steam generation or export. The Kemmerer plant has chosen to burn this gas in the front-end afterburner to generate steam, and in the back-end afterburner to incinerate the remainder.

Sulfur in the coal may be a consideration here. The fuel gas, from the carbonizer and calciner, can contain about 900 ppm by volume of hydrogen sulfide, for example, when a 1%-sulfur coal is the feed. The Kemmerer plant does not desulfurize the generated fuel gases, but future FMC coke plants will have sulfur-removal facilities. One of the many demonstrated commercial desulfurization processes will be the choice.

Instrumentation of the system (Fig 3) is pneumatic, like that of the rest of the plant. Another reason, besides compatibility, was fear that coke dust might penetrate electronic instruments and give operating and maintenance problems. ■

FMC Corp, Kemmerer, Wyo: Principal retrofit equipment

Heat-recovery equipment

Afterburner, 1 .... Bigelow Liptak Corp
120-million Btu/hr, 0.5-in.-H_2O design pressure, 2200F design temperature, 15 ft diameter × 60 ft long with 9 ft diameter × 80 ft high stack (carbon-steel shell with castable-refractory liner)
Heat-recovery boiler, 1 .... Deltak Corp
30,000 lb/hr at 450 psig/461F
Forced-draft fan, 1 .... Chicago Blower Corp
15,882 acfm of −40F air at 11.5 psia, 21,175 acfm of 100F air at 11.5 psia, 40-hp motor drive
Induced-draft fan, 1 .... New York Blower Co
Handles gas at temperatures up to 800F, 75-hp motor drive
Coal-dust fan, 1 .... Chicago Blower Corp
6883 acfm of −40F air at 11.5 psia, 9177 acfm of 100F air at 11.5 psia, 40-hp motor drive
Pilot air/gas fan, 1 .... Maxon Corp
1.2-million-Btu/hr capacity
Sootblowers .... Copes-Vulcan Inc
One semiautomatic retractable blower and four manual rotary blowers, blowing medium is 450-psig steam
Fuel-oil pumps, 2 .... Roper Pump Co
One required for normal operation, one on standby; each 5 gpm at 140 psig, 1.5-hp motor drive
Wastewater pump, 1 .... Roper Pump Co
16 gpm at 132 psig, 2-hp motor drive

Catalyzer off-gas condensing/scrubbing system

Condenser/scrubber, 1 .... Croll-Reynolds Co
300F inlet temperature, 140F outlet temperature, 13,300 acfm at 300F
Recycle cooling pond .... Ted's Construction Inc
Four cells, 871,200-cu ft total volume
Scrubber supply pumps, 2 .... Goulds Pumps Inc
One required for normal operation, one on standby; each 660 gpm at 69 psig, 50-hp motor drive
Scrubber return pumps, 2 .... FMC Corp, Peerless Pump Div

Inert-gas cooling/scrubbing system

Cooler/scrubber, 1 .... Croll-Reynolds Co
Cooling tower, 1 .... Baltimore Aircoil Co
Cooler/scrubber supply pumps, 2 .... Goulds Pumps Inc
Inert-gas compressors, 2 (existing) .... Fuller Co

Condensate and feedwater systems

Deaerator-feed tank, 1 .... Titan Steel Corp
10,000 gal, 10 ft diameter × 18 ft high
Deaerator-feed pumps, 2 .... Goulds Pumps Inc
One required for normal operation, one on standby; each 42 gpm at 38 psig, 5-hp motor drive
Deaerator, 1 .... Aqua-Chem Inc, Cleaver-Brooks Div
15-psig operating pressure, 1000 gal
Boiler-feed pumps, 2 .... Goulds Pumps Inc
One required for normal operation, one on standby; each 85 gpm at 514 psig, 60-hp motor drive
Condensate separator tank, 1 .... Winston Engineering Co
Chemical-injection pumps, 2 .... Milton Roy Co
Boiler-water sample coolers, 2 .... Betz Laboratories Inc

Compressed-air system

Air compressors, 2 .... Ingersoll-Rand Co
One required for normal operation, one on standby
Instrument-air dryer, 1 .... C M Kemp Manufacturing Co

Standby power system

Diesel/generator, 1 .... Kohler Co
250-kW, 312.5-kVA standby rating

Cutting demand with a custom system

Management said: 'Take a close look at demand charges, find out if any loads can be shed and then restored within the demand period, and build a control system that will do the job.' Here's what company engineers did—with some surprising results

By J D Horn, Masonite Corp and **R P Grehawick,** General Electric Co

In August 1975, after the cost of electricity had soared 111% in three years, the management of Masonite Corp, Laurel, Miss, requested that its Energy Conservation Dept analyze the feasibility of a demand limit-control system and implement it by May 28, 1976—the date when the demand charge for the next 12 months was to be set by Mississippi Power Co.

At Laurel, the kW requirement each month is the average kW required from the power company during the 15-minute period of the greatest use as measured by a watt-hour meter, but it cannot be less than the largest of the following contractual stipulations:

- Contracted kW requirement.
- Maximum kW requirement established during the most recent calendar months of June, July, August, and September.
- 90% of the maximum kW requirement established during any of the remaining eight calendar months during the most recent 12-month period.

The monthly billing is one-twelfth of the foregoing annual charges adjusted in accordance with power demand, power used, fuel-cost adjustment, and power factor. The power a customer uses is measured by the utility, and the highest rate used in any 15-minute period during a month establishes the demand rate for the coming year.

Studying the problem. When the Energy Conservation Dept began to study the problem, its personnel had no idea what Masonite Corp paid for electric services each month. They were amazed at the costs compared to three years earlier. It was enough to convince them that something had to be done, and fast.

Distribution of power throughout the plant was studied and analyzed. At the same time, information on demand-limit controllers from several manufacturers was accumulated. However, the department didn't rush out to buy the control equipment before the problem was identified and a solution proposed. Instead, it rented some 20 recording meters and installed them in all the large load areas in the mill.

Analysis indicated that almost 50% of the entire plant load was concentrated in the seven production units where wood fiber, mixed with water to make hardboard, is refined. From the refiners, the stock flows onto the wet machine.

What is critical to production is that the stock tanks feeding the board machines be kept filled so formation of the mats on the wet lap are not interrupted by shutdowns. As long as the slurry in the stock tanks are kept above a minimum level, it is possible to control the power load within the 15-minute periods without affecting the production rate or product quality.

Building a customized system

After studying available literature on demand limit controllers for other plants and processes, it became obvious to department engineers that none of these systems would work at Laurel. They were designed to shed and restore loads automatically, such as cooling units, ventilation systems, and electric furnaces. You can't shut a board machine down every 15 minutes, however, and stay in business very long.

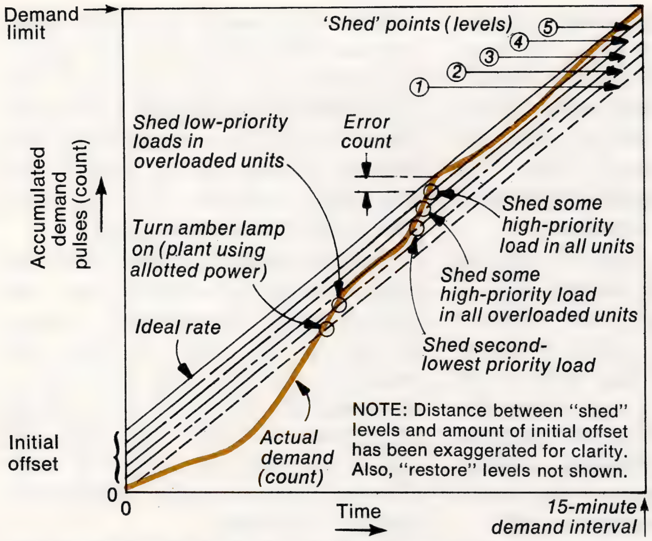
Laurel engineers concluded that not enough motors could be stopped and restarted to reduce the demand appreciably. However, it was seen that if loading on the large motors could be carefully regulated rather than allowed to fluctuate, the peaks could be reduced. The department then went to work to design a system that would force the machinery operators to load their machinery carefully and uniformly. The system would penalize only those plant areas that became lax in controlling their equipment.

By exploring many ideas and keeping only the viable ones, department engineers began to build a customized demand-control system that would operate without affecting quality or production. Once it was known where demand could be reduced, the search began for hardware that would do the job.

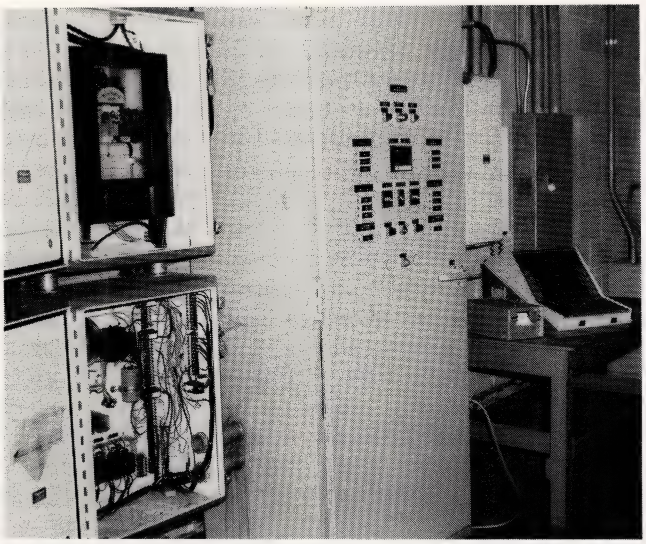
What is unique about the demand-control system at Masonite Corp is that it goes beyond automatic shedding and restoring of loads at predetermined levels of priority. Engineers built into the system a series of warning signals so operators at the production units could monitor advance warnings on excessive load demand and take corrective action. The operators would know best what refiner or refiners to cut back on without affecting the continuous feed of slurry from the stock tanks to the board machines. Only when warnings go unheeded does the system take over automatically and start shedding loads.

As a result of this design modification, operating efficiency has increased measurably. Where once the process was cyclic, it is now smooth and continuous.

The brains of the demand control system is a programmable controller, which was ordered while plant engineering and maintenance personnel



1. Accumulated demand pulses are plotted against time in demand control system to keep tabs on actual demand



2. Programmer and printer (right), programmable control panel (center), demand recorder (top left), relay (lower left)

were designing and installing the necessary circuits and equipment needed for the customized system. Remember, the system had to be finished by May 28, 1976 because the highest demand peak set after that date would establish the plant's demand rate for the next 12 months. As it happened, the completed system was placed in operation on that date—only one hour before the meters were read by the power company.

How the system works. The world of control may be broken down conveniently into inputs, outputs, and logic decision-making devices including, more recently, programmable controllers.

Programmable controllers are used in a variety of applications, chiefly machine control, to replace large banks of hardwired relay circuits, because they can be programmed faster at a programming panel than by manually rewiring relay circuits. The same general-purpose programmable control hardware has been applied recently to demand-limit control, using relay diagram symbology.

At the Laurel plant, the control equipment represented by the three control categories looks like this:

Inputs are two kinds of pulse signals received from the power company. The first is a synchronizing pulse, which resets the demand period every 15 minutes. The second is an energy pulse, which measures with a watt-hour meter how many kWh are actually being used (see Fig 1 above). Each pulse represents 100 kWh. Both of these pulses are contact closures. Thumbwheels, pushbuttons, and selector switches are used to enter parametric data, such as the ideal count, the initial offset, the demand limit, real time (actual time of day in hours and minutes), day of year, and shed and restore priorities for each load.

Outputs are light emitting diodes (LEDs) for numeric display on the console and indicating lights, such as a green light for "system running," a red light for "demand limit exceeded," and an amber light for "ideal rate exceeded." There are also indicating lamps next to function name tags on the control console. Other outputs are the actual automatic shed signals.

Decision-making devices. The input and output devices are hardwired to terminal blocks on input/output (I/O) cards, which are inserted in slots on I/O racks located in the control console. This console is a freestanding, floor-mounted device with a 90-in.-high NEMA 12 enclosure. The I/O racks are connected via one cable to the programmable controller's central processing unit (CPU), which is the logic decision-making device.

The CPU reviews the status of various input devices every 5 msec. and makes a logical decision based on the relay ladder diagram stored permanently in its plated-wire memory. (The entire relay ladder diagram is solved, or evaluated, every 14 msec.) Based on the review, the CPU turns on the various outputs.

Adapting the standard program. At Laurel, the programmable display permits checking of the 384 functions in the programmable controller. These functions, which can be relay, latched relay, on-delay timer, off-delay timer, motor-driven timer, counter, shift register, and arithmetic function, were combined to form a program called *programmable demand limit controller.*

This standard software program was tailored slightly for the Laurel plant. For example, a printer (Fig 2) was added for hard copy of any one of nine separate message codes. These codes, printed in red or black, are read from bottom to top. Each message consists of one, two, or three lines. The nine message codes (001 through 009), with code 001 the highest priority, are:

Shed action (red)
Restore action (black)
Meter relay closed (red)
Meter relay opened (black)
Demand limit exceeded; actual counts shown (red)
Acknowledges demand limit exceeded (black)
Negative error whenever actual count greater than ideal count (red)
Return from negative error (black)
New peak set (red)

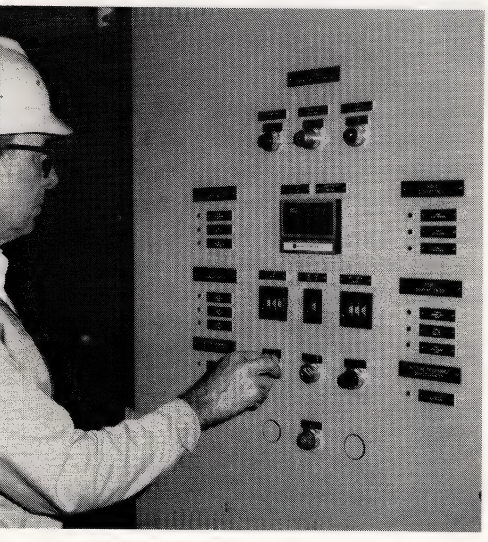
The control strategy of the program implemented at Laurel is to receive kWh pulses from the utility's

watt-hour meter. These pulses are accumulated and compared to a predetermined ideal demand rate of accumulation, which is generated by the programmable controller. The difference between the two curves is used to determine (1) when a controller load is to be shed, so as not to exceed the total demand limit at the end of the 15-minute demand period, and (2) when to restore load so the actual load curve will come as close as possible to the predetermined limit without exceeding it (Fig 1). The reason for the latter: because Masonite is already paying a demand charge based on the highest peak in the last 12 months, it is good economics to use as much as possible of the demand it is paying for without exceeding the limit.

Interposed between the power loads and the programmable controller are demand-control-center panels for each of the production-unit-load areas. These panels receive inputs from meter relays, which respond to kW load of the individual units and the demand limit controller. They provide warnings to unit operators on the status of electrical demand both for the unit and the entire plant load. Each panel has four lights; also, each panel is connected to whistles and horns.

At the top left of each panel is a white lamp, which indicates, "Your area is using allotted power." At the bottom left, a green lamp indicates, "Your area is using more than allotted power; you're overloaded."

3. Programmable control panel showing operator setpoints and displays



Simultaneously, an amber lamp at the top right of each panel indicates, "The plant is using allotted power." If both the white and amber lamps are lit, the unit and the plant are using allotted power; thus, "Be prepared for a request to cut load in your area" is then indicated.

If the green and amber lamps are on, the operator is warned that he has to cut back on a load within 5 minutes to avoid a plant overload. When the green lamp and a red lamp at the bottom right flash, the operator is told, "Both your unit and the plant are overloaded. Reduce load within 60 seconds or get a shed action." Also, a howler is set off.

If no actions are taken by the operators, automatic shed actions are taken by the power-demand-control system.

Using demand-control centers in conjunction with the plant programmable-demand-limit controller permits operators to decide which refiners can be shut down temporarily, while still maintaining the needed production level. The strategy gives the operator a keener awareness of the need for efficient use of electricity, and only removes the human decision-making element when advance warnings are ignored.

The programmable controller (Fig 3), which is housed in the switchgear room, can be monitored by maintenance personnel with various output devices on the control console. On the left side of the console are six display functions related to the ideal rate, which can be dialed by a thumbwheel switch for an LED numeric display. Similarly, on the right side are six functions representing information on actual demand. The displays show this:

Ideal demand rate	Actual demand
Time remaining (× 0.1 min)	Count remaining
Ideal count	Actual count
Time in period (× 0.1 min)	Error count
Initial offset count	Demand-limit count
Real-time hours	Real-time minutes
Day of the year	Peak-demand count

A red lamp at the top left of the control console indicates that the demand limit has been exceeded; it is an alarm/reset signal. An amber lamp at the top right indicates, "Ideal rate exceeded." In the top center is an off/on key switch.

Below the display functions, name tags described above are shed points, on the left, and restore points, on the right, which are entered by thumbwheel switches in the function load selector. Lights at the bottom left and right indicate, "Set up complete" and "System running."

Control system flexible. The programming panel is located near the main console. In addition to programming the logic circuits, the panel can also be used for troubleshooting the system. It can call up all circuit diagrams one by one, which can then be compared with the same diagrams maintained in the operator's manual.

When the system was first started up, it controlled 46% of the total plant electrical load. Now it controls 38%. The 8% difference represents the savings on power usage, the bonus received by Masonite Corp in addition to reducing its demand charge. Because only five of the six shed and restore points on the programmable controller were used at Laurel, there is still room to fine tune and expand the system.

When Masonite Corp engineers first became immeshed in this project, they found it was important to concentrate on areas with the heaviest loads and then work back, instead of trying to control demand on the entire electrical load at once. Too often, plant engineers run out and buy a demand-control system before they know precisely what they are going to control.

Savings achieved. Since the system at Laurel was started up, demands during the first year were reduced 4500 kW, saving Masonite Corp at least $220,000; demands were limited even more in the second year. Demand reduction has been achieved without any loss of production or product quality and, in fact, operating efficiency has increased.

A bonus observed during the past year has been an actual drop in electrical energy use as a result of more efficient operation at various load centers. This has saved an additional $144,000 per year. So the system that cost the company $50,000, (programmable controller, meter relays, strip chart recorders, and other associated electrical equipment and wiring) paid for itself in less than three months. ■

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For complete information, contact FMC Corporation, Turbo Pump Operation, 326 South Dean Street, Englewood, New Jersey 07631. Phone: (201) 568-4700. Telex: 135335.

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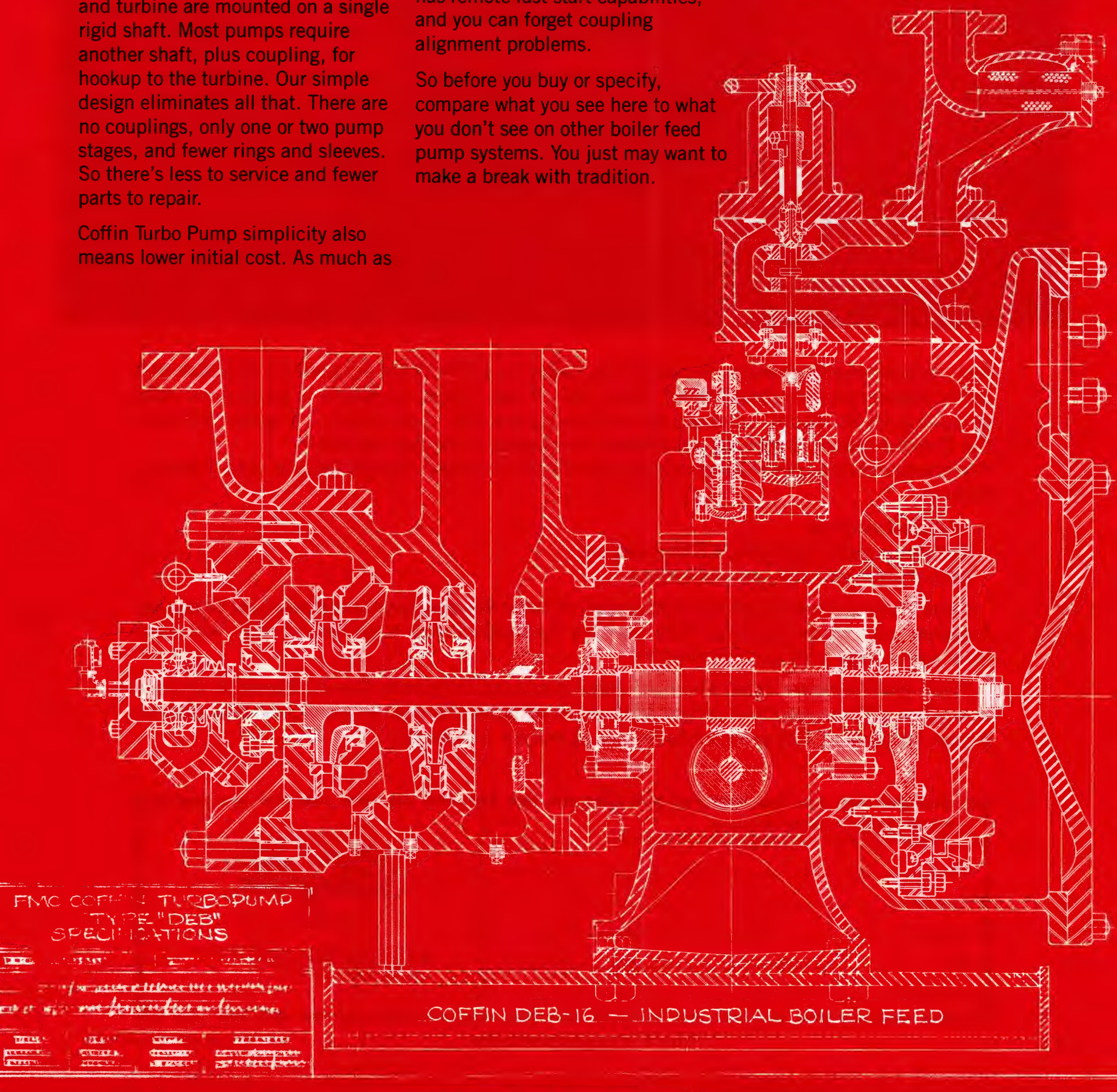

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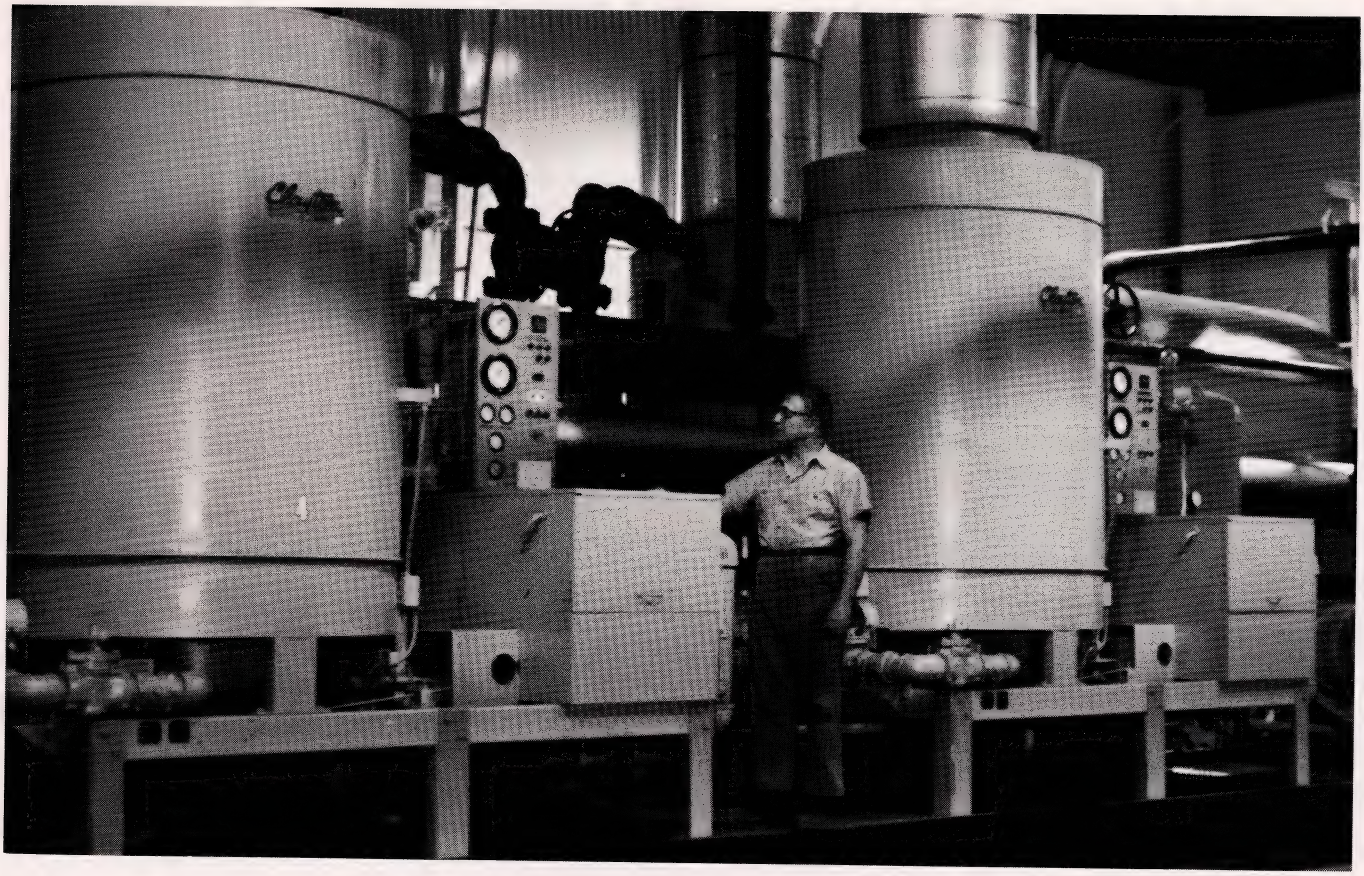

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CIRCLE 36 ON READER SERVICE CARD

Tretolite additives for lower grade fuels: The Energy Extenders.

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But Tretolite can help, with the Energy Extenders . . . industrial fuel-treating chemicals and technology that alter crude oils, residuals, and contaminated distillates to minimize maintenance, downtime, and equipment expenses in all phases of fuel usage.

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TOLAD* Fuel Additives from Tretolite disperse the sludge and sediment that restrict flow, plug lines and strainers, diminish pre-heater performance, and foul nozzles. TOLAD Cold Flow Improvers facilitate the winter storage and handling of heavy fuel oil. X-CIDE* Industrial Bactericides stymie the growth of corrosion- and sludge-causing bacteria in water associated with fuels. KONTOL* Corrosion Inhibitors prevent corrosion of pipes, pumps, valves, and other metal parts. TRET-O-LITE* Demulsifiers aid the removal of water from fuel, either in treating systems or through static separation in tanks.

Fireside

In hot parts of equipment, metallic impurities create deposits which impede heat transfer and cause high-temperature corrosion and refractory damage. Oil-soluble KONTOL Corrosion Inhibitors—based on magnesium, aluminum, and silicon—reduce these problems by modifying the composition of the combustion products to effect dry, non-tenacious ash which is not retained in the equipment. Recommendations are based on contaminant levels in the fuel for the most efficient and effective application. Manganese-based KONTOL Combustion Improvers allow minimum excess air operation to accomplish the same results.

Post-combustion

Cold-end corrosion, caused by SO_2-SO_3 conversion and sulfuric acid from sulfur-containing fuels, is prevented by appropriate KONTOL additives which interfere with formation of SO_3, lower the dew point, and react with the sulfuric acid to neutralize it.

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TRET-O-LITE Demulsifiers are available in a wide variety of formulations to meet individual treating requirements in fuel-water washing systems for removal of water-soluble salts. Oil-soluble KONTOL High-Temperature Corrosion Inhibitors are injected into washed fuels to produce properly inhibited stable fuels suitable for use in gas turbines. These high-quality materials are specifically designed to meet manufacturer's warranty requirements. Unwashed fuels containing low levels of alkali-metal contaminants may be inhibited by certain KONTOL additives to forestall sulfidation and vanadic corrosion.

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Water used in stack gas scrubbers, cooling and effluent water systems can be efficiently treated—with TOLFLOC* Flocculants, TOLSPERSE* Dispersants, SP* Scale Preventives, KONTOL Corrosion Inhibitors, and X-CIDE Bactericides—to restore it to specified standards for recycling or discharge.

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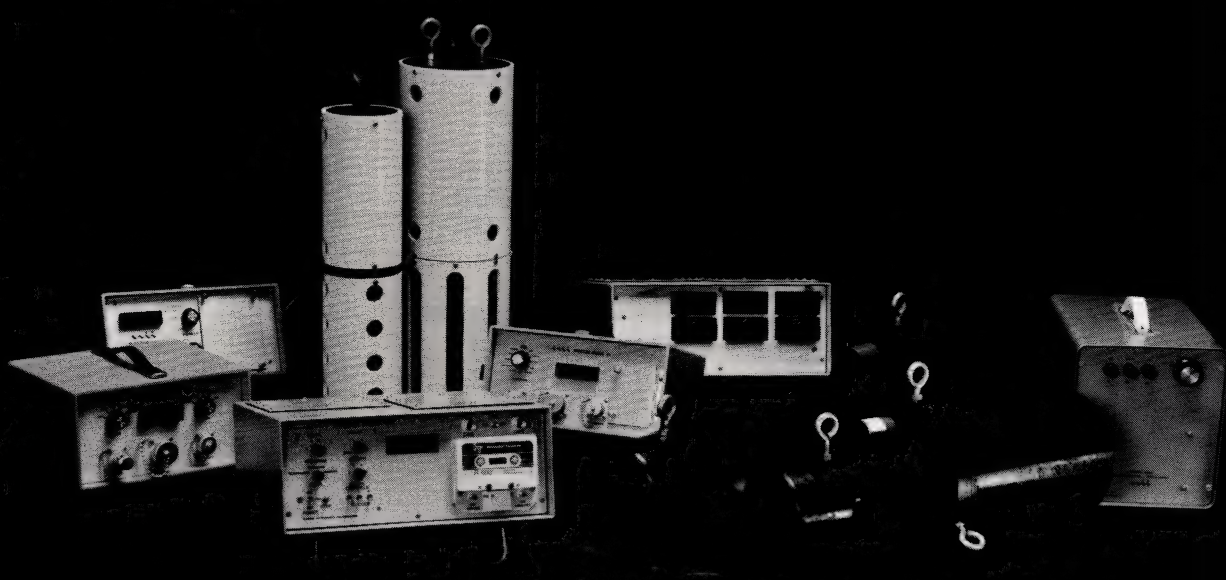

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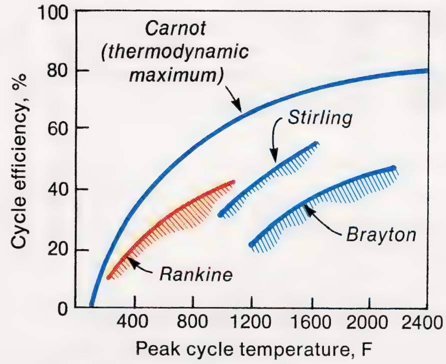
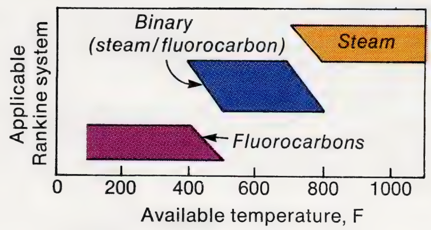
Reclaim more energy from plant waste heat

The binary Rankine cycle uses steam and refrigerant as working fluids to reclaim low-level waste heat from stacks, condensing vapors, and hot liquids in a one-plus-one-equals-three strategy

By R K Rose and **D D Colosimo,** Mechanical Technology Inc



1-2. Thermodynamic potential of various engine types is shown above, temperature ranges of Rankine systems below



The selection of a Rankine cycle for bottoming low-temperature waste streams is straightforward. Although other thermodynamic cycles such as the Stirling and Brayton can achieve higher efficiencies, as shown in Fig 1, they are not applicable at low temperatures. The Rankine cycle offers the highest thermodynamic potential in the range of interest to electric utilities and many industrial companies.

Use of the Rankine bottoming cycle is limited by some economic considerations which relate to the temperature of the heat source and to the overall size of the system. For example, as the waste-source temperature decreases, the price of a bottoming cycle increases. This is simply a reflection of the thermodynamics: The lower the temperature, the less the power that can be delivered for a given amount of heat-transfer surface and installed turbomachinery.

The overall size of the system, as reflected by the quantity of waste heat at a given source temperature, also affects the unit cost of a Rankine cycle. A portion of system costs is fixed or is relatively insensitive to unit size. Thus, as these fixed costs are spread over a larger system base, the unit cost of a bottoming cycle decreases. Currently, a unit installed cost of from \$1000 to \$1200/kW is anticipated for production systems.

The perception of the economic market distribution affects the selection and design of a Rankine bottoming cycle, as shown in Fig 2. If the market is at high temperatures, a steam Rankine system is the obvious choice; if the market is at low temperatures, an organic Rankine system based on the conventional refrigerant fluorocarbons is the choice. In the mid-temperature range, however, the Rankine-cycle fluid choice is not as obvious as you might think.

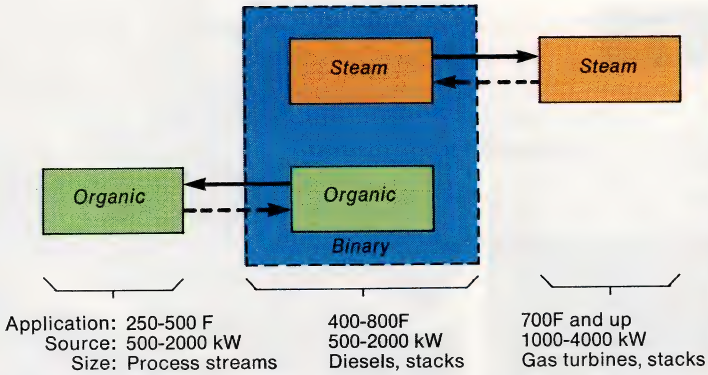
Hydrocarbons and some exotic fluorocarbons present some very attractive thermodynamic and aerodynamic incentives. However, the actual and perceived risk of these fluids because of their flammability, toxicity, availability, and/or cost, makes a binary Rankine cycle based on the use of steam and a fluorocarbon refrigerant attractive.

The binary Rankine cycle satisfies an identified market—that is, heat recovery from the diesels at municipal electric-utility plants—and provides the basis for demonstrating three Rankine system concepts as shown in Fig 3. The binary Rankine cycle satisfies the mid-temperature range waste-heat market.

Bear in mind that, since the steam portion of the binary Rankine cycle interacts with a hot gas stream, it provides the basis for serving the high-temperature stack-gas. And, since the organic portion of the cycle interacts with a condensing stream at low temperature, it can serve the low-temperature waste streams characterized by condensing vapors and hot liquids. This one-plus-one-equals-three approach uniquely positions the Rankine bottoming cycle for serving the full range of industrial waste-heat streams.

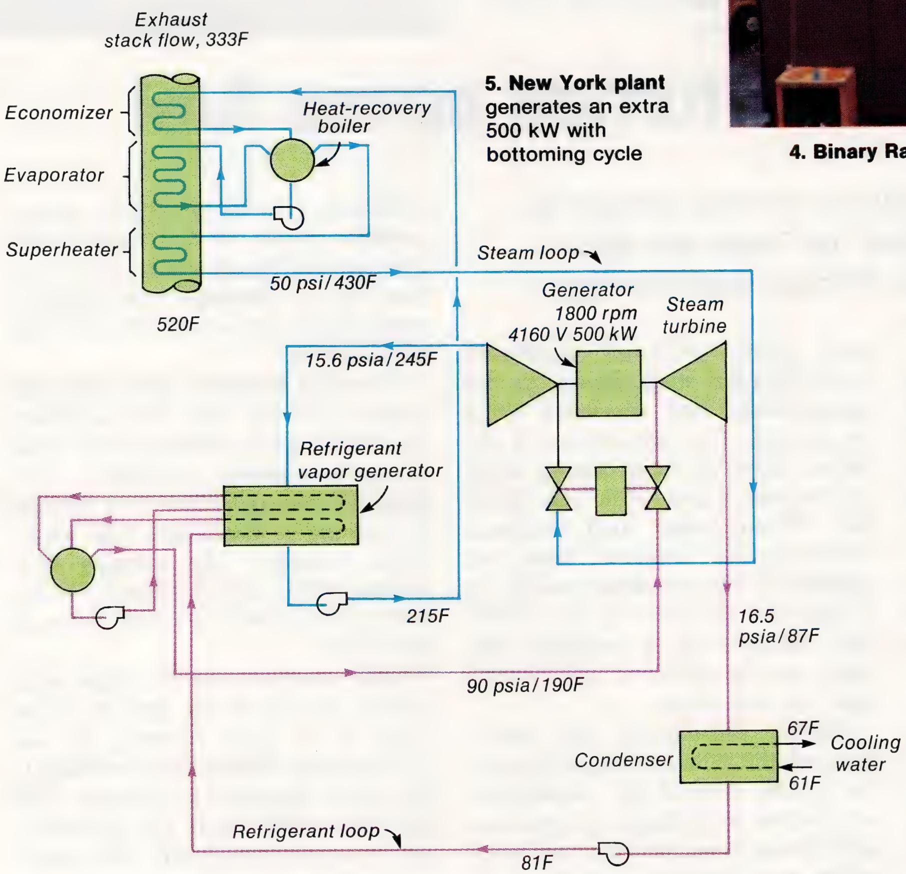
Engineers have identified numerous other characteristics that a successful Rankine bottoming cycle must possess in order to serve the industrial waste-heat market. To illustrate: Bottoming cycles will be rather small in total capacity, ranging from 500 to 4000 kW. The economies-of-scale indicate that Rankine cycles of this size must be highly efficient and be designed and built as an off-the-shelf system. Custom engineering would make the units totally uneconomic; extensive field-erection requirements would also destroy the cycle's economic feasibility.

Rockville Centre. In April 1976, the Energy Research & Development Administration (now DOE) awarded Mechanical Technology Inc (MTI) a contract to design, develop, test, and demonstrate a binary Rankine cycle. The binary-cycle concept is viewed as serving small-scale waste-heat flows in the temperature range from 400 to 700F. In this range, neither steam nor common fluorocarbons are effective as single-fluid systems. Small



3. System criteria reveal benefit of organic cycle to industry

4. Binary Rankine cycle as installed at Rockville Centre



5. New York plant generates an extra 500 kW with bottoming cycle

steam systems have both thermodynamic and mechanical design problems; the common fluorocarbons have fluid stability problems.

Last March, MTI officially dedicated the first installation of a binary Rankine cycle on a municipal electric-utility diesel plant. The municipality is the village of Rockville Centre, located on Long Island, NY, about 10 miles from Kennedy Airport. The overall installation is shown in Fig 4. The Rankine system can operate from either or both of two diesel engines, each 5.5 MW.

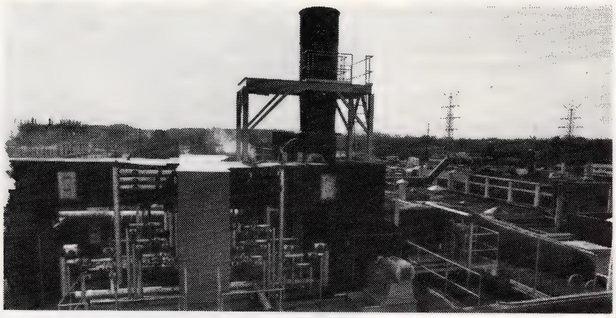
The actual cycle state points utilized in the binary demonstration are shown in Fig 5. The steam loop interfaces the hot exhaust gas with a heat-recovery boiler that is well within the state-of-the-art. In this system, the 520F exhaust from the diesel is reduced to 333F. A lower exhaust temperature from the boiler is feasible, but MTI engineers chose to pick conditions which would totally avoid the potential of stack condensation. A feature that reduces the potential of condensation, provides natural deaeration, and eliminates both an efficiency loss and an extraction heat exchanger is the return of the steam condensate to the economizer at 215F.

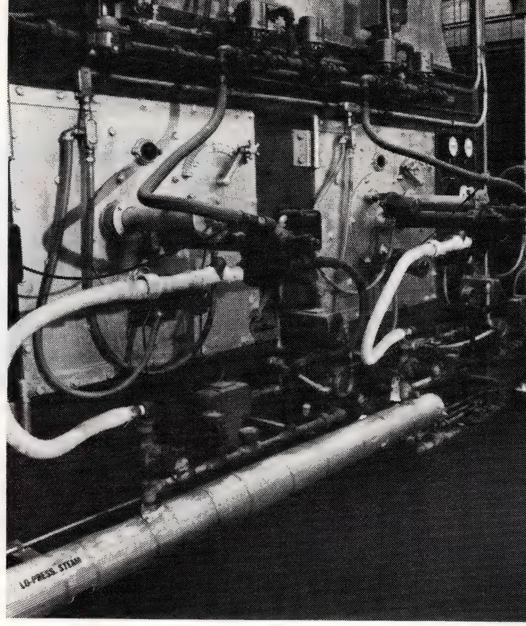
Steam from the boiler is expanded through a high-speed (42,200 rpm), high-efficiency (85%), single-stage radial in-flow steam turbine. The steam exits the turbine at 1 psig and is condensed by the fluorocarbon refrigerant, R-11. The fluorocarbon vapor is expanded through a single-stage radial in-flow turbine and exits at 2 psig. The vapor is condensed by cooling water from a cooling tower which is included in the total package. The avoidance of subatmospheric pressures simplifies the noncondensable-gas removal systems and keeps the machinery and piping sizes small.

Operational control of the system at Rockville Centre was transferred to the municipality in late summer, after completion of system shakedown testing and minor modifications required by changes in the operational procedures at the utility over the past year. The transfer of control marked the start of a three-year demonstration effort. ■

MTI is participating with DOE in two Rankine system demonstration programs. The first is the binary Rankine cycle demonstration at Rockville Centre and the second is a cooperative venture program designed to demonstrate organic, steam, and binary Rankine systems.

PACESETTER PLANTS





1-2. Fume duct from phenolic treaters enters boiler room via roof (above). Burner front and control panel of the No. 6 steam generator are shown at right after retrofit.

Burning process fumes saves fuel

Fume incineration system captures process exhaust for reuse as combustion air, cutting fuel costs and also ending an emissions problem. Efficient control is key

At Nevamar Corp's phenolic treatment plant in Odenton, Md, process exhaust doubles as combustion air to eliminate emissions and reduce fuel costs. Exhaust fumes from three phenolic treater ovens are diverted to two plant boilers (Fig 1) to provide the combustion air.

Fumes incinerated. The high-temperature fumes contain minute traces of hydrocarbons, which are highly desirable for combustion purposes. The hydrocarbons are incinerated (oxidized) in the boiler furnace and exit the stack as carbon dioxide and water. Using the air twice, once in the process and again in the two boilers, reduces the total amount of heat exhausted to atmosphere, thereby lowering overall plant heat losses and saving on fossil fuel.

The system was designed and installed by Power & Combustion Inc. The retrofit entailed: (1) installation of ductwork and fans for conveying process exhausts to the boiler room (Fig 2), (2) modification of two existing boilers required by the new high-temperature combustion air, (3) addition of a burner-management system (Fig 3), and (4) updating of combustion controls for safety and efficiency.

Incineration system operation. Exhausts from the three process units are ducted to the roof of the boiler room, where they enter the forced-draft (FD) fan inlets. Boiler furnace temperatures and residence times are suitable for incineration of the hydrocarbons in the exhausts, which are burned along with the boiler fuel. When boiler load increases combustion air demand above that supplied by the exhausts, outside air is admitted to make up the difference. Outside air is required only when one or more of the process units are shut down.

During periods of low steam demand, the exhaust volume exceeds the volume needed for combustion air. To prevent leakage of hydrocarbons during these periods, the No. 6 boiler was modified to include an incineration zone within the furnace. (Leakage is caused by reduced furnace temperatures that accompany low firing rates with high excess air, which can also quench the fires.) Excess exhaust is injected into this zone for incineration of the hydrocarbons.

Controls for the boilers are of the full-metering type with cross-limiting capability. Combustion-air controls are split-ranged to draw process exhausts in preference to outside air. Each combustion air source is fitted with its own damper and drive.

A separate control loop maintains atmospheric pressure at process unit exhausts (1) by diverting excess exhaust fumes to the incineration zone of the No. 6 boiler, or (2) by limiting the opening of the dampers controlling process exhausts entering the FD fans.

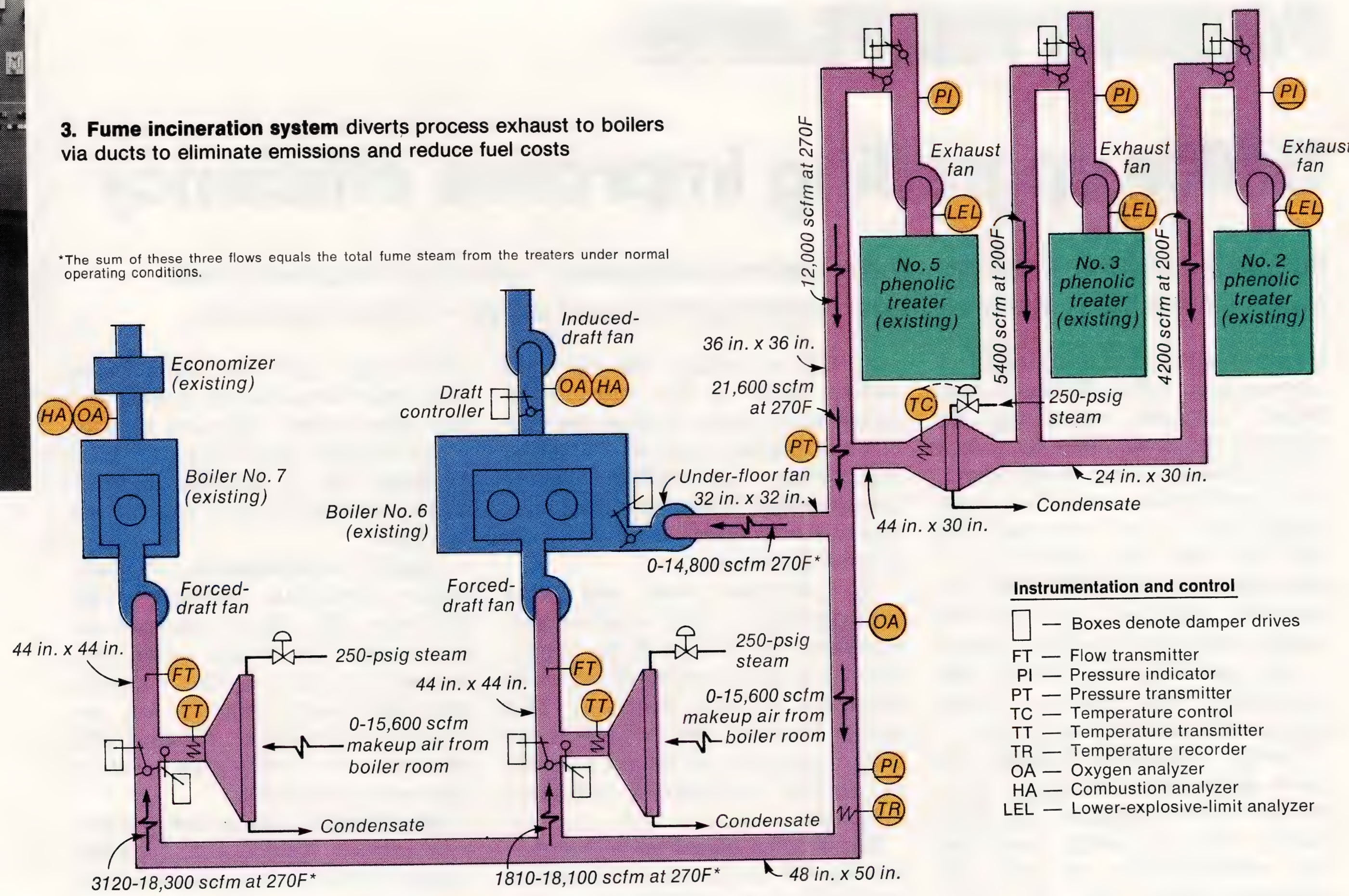
Diverting dampers. Each phenolic treater is fitted with dual dampers for diverting the exhaust to the boiler-intake-system ductwork. The dampers are connected by a linkage to a common diaphragm-type pneumatic actuator. The actuator is a spring-return unit, arranged for diverting the exhaust to atmosphere on air failure.

LEL analyzers. In the event of a "spill" in one of the process units (that is, a large increase in the hydrocarbon content of the exhaust), the unit's dampers are tripped and the oven is shut down. The trip function is accomplished with LEL (lower explosive limit) analyzers installed on the process units. A fourth LEL analyzer monitors combined streams from all process units to provide redundant protection.

Oxygen analysis. The presence of varying amounts of hydrocarbons in the combustion air required an oxygen-trim system to adjust the air/fuel ratio for minimum excess air firing. A spill could add enough hydrocarbons to alter the air/fuel ratio by 20%—without tripping via the LEL analyzers. Also, hydrocarbons combine with oxygen in the furnace to reduce the amount of oxygen available for combustion.

To obtain a control loop that

3. Fume incineration system diverts process exhaust to boilers via ducts to eliminate emissions and reduce fuel costs



*The sum of these three flows equals the total fume steam from the treaters under normal operating conditions.

compensated for both these factors required the addition of a zirconium-oxide analyzer. Gas flowing through the analyzer is heated to a temperature high enough to ignite hydrocarbons. The analyzer output is a "net" oxygen value proportional to what is available for boiler firing. This provides a signal for modifying the air/fuel ratio.

Further precautions. During operation on outside air when process exhaust is not available, or when exhaust volumes are far lower than the volumes needed for combustion air, the fan used to inject excess exhaust fumes into the incineration zone of No. 6 boiler is shut down. To prevent leakage of furnace gases into the ductwork (damper leakage creates negative pressures in the ductwork), a vent damper admits outside air to offset the leakage and provide a light air flow into the incineration zone.

The outside air used for combustion air makeup is preheated with steam to prevent cooling of the blended process exhausts, which could cause condensation of hydrocarbon vapors. Also, the higher temperature air is required to prevent overloading of fan motors.

Results to date have been gratifying. Yearly savings in boiler fuel have ranged generally between 4 and 8% since the January 1976 startup. Visible emissions from the treater ovens are no longer objectionable. ■

Nevamar Corp, Odenton, Md: Principal retrofit equipment

Steam generator and auxiliaries

No. 7 boiler forced-draft fan, 1 ....Buffalo Forge Co
Centrifugal radial-tip type with 3/16-in. split steel housing, flanged inlet and outlet, housing drain, access door, shaft seal, grease-lubricated ball bearings, designed for 600F service, flexible coupling connects motor and fan, 30,840 acfm of 70F air at 27.2 in. H_2O; 150-hp, 1180-rpm, 460-V motor drive

No. 6 boiler forced-draft fan, 1 ....Buffalo Forge Co
Centrifugal radial-tip type, 30,530 acfm of 70F air at 8.4 in. H_2O; 75-hp, 1180-rpm, 460-V motor drive

No. 6 boiler under-floor fan, 1 ....Buffalo Forge Co
Centrifugal radial-tip type, 25,000 acfm of 70F air at 7.8-in. H_2O; 50-hp, 1180-rpm, 460-V motor drive

No. 6 boiler induced-draft fan, 1 ....Buffalo Forge Co
Centrifugal radial-tip type, 52,680 acfm of 70F air at 9.5 in. H_2O; 100-hp motor drive

Air heaters (steam-coil), 2.. Aerofin Corp
Each consists of three coils designed to heat 15,600 scfm of 70F air to 264F with 200-psig steam, copper tubes have 0.049-in. wall thickness and 12 fins/in.

Fume-stream reheat coil, 1.. Aerofin Corp
Consists of three coils designed to heat 9600 scfm of 200F air to 290F with 200-psig steam, copper tubes have 0.049-in. wall thickness and 8 fins/in.

Fume-stream booster control valve, 1............ Spence Engineering Co
Controls fume-stream temperature between 150 and 300F

Windbox/burner assembly, 1. . . .
. . . .Peabody Engineering Corp/Power & Combustion Inc

Fume-stream control panel assembly, 1. . . .
. . . .Peabody Engineering Corp/Power & Combustion Inc

No. 6 boiler combustion controls. . . .
. . . .Peabody Engineering Corp/Power & Combustion Inc

Miscellaneous transmitters, indicators, valves, actuators. . . .
. . . .Bailey Controls Co, Honeywell Inc, Fischer & Porter Co

Boiler upgrading improves efficiency

Pulp mill installs new burners and a burner-management system on its power boiler, and switches the primary fuel from natural gas to wood waste—a plant byproduct

Northwood Pulp Ltd operates a 750-ton/day kraft mill in Prince George, British Columbia which was designed in the early 1960s to operate on purchased electric power and to use natural gas as a major fuel stock. Energy costs were extremely low when the mill was started up—5 mils/kWh and 40¢/1000 cfm, respectively. However, the mid-1970s energy crisis quickly became evident in mill operating costs, which rose alarmingly. Thus, efforts to reduce energy costs received top priority.

Energy committee findings. To better define areas of energy wastage and establish programs for eliminating them, an energy committee was established in the mill. On reviewing energy costs, the group immediately focused on high natural-gas usage and cost.

When it discovered that roughly 60% of all the natural gas consumed by the mill was burned in the power boiler, this unit came under close scrutiny (see equipment list, following page). It was designed to burn natural gas primarily, although hog fuel—considered a nuisance byproduct initially—could be burned in addition, on a water-cooled pinhole grate, to yield a steam rate of 250,000 lb/hr.

Because the hog fuel is essentially free, however, a simple plan was established to fire the boiler *primarily* with this wood waste. When the rate of hog firing was increased, two obvious shortcomings of the power boiler were observed:

- At hog-burning rates in excess of 240,000 lb/hr, particulate emissions became excessive, resulting in a black stack condition that exceeded British Columbia's particulate limit of 0.15 gr/scf.
- As the percentage of hog-fuel firing was raised, boiler control became increasingly difficult. The mill's turbine/generator—installed in 1973 to reduce the electrical import needs of the mill—aggravated the problem. Because the boiler was designed to use natural gas as the primary fuel 75,000 lb/hr of gas-generated steam was needed to assure steady steam pressure to the turbine/generator.

To overcome these and other shortcomings, a boiler-improvement program was developed by a mill-wide task force ranging from boiler operators to mill manager. This group provided diverse inputs on boiler operation, which are valuable in putting together a workable program.

Initial boiler objective. Although it was agreed that the boiler should be modified to burn 100% hog fuel, the precise firing rate could not be easily defined. It was necessary, therefore, to determine the hog-burning capabilities of the unit. To achieve this, the boiler manufacturer was commissioned to restudy its equipment.

The study indicated that the boiler was not quite capable of meeting the permit discharge limit for particulates when producing a total of 300,000 lb/hr of steam with 250,000 lb/hr from hog fuel. Moreover, when firing at rates of 400,000 lb/hr, with 330,000 lb/hr coming from hog fuel, particulate emissions were more than twice the allowable limit. From this information, engineers thought that a realistic objective for the boiler would be to produce approximately 300,000 lb/hr of steam from hog fuel.

Specific improvements. To help reduce particulate emissions from the boiler, the original overgrate air fan, unused for several years, was put back into service. Also, a continuous particulate monitor was installed on the stack, allowing mill personnel to study the factors influencing emissions.

New burners and a new burner-management system were installed in mid-1978 in order to improve boiler operation (see box and photo). The modification would, in time, enable the power boiler to run on almost 100% hog fuel.

At that future stage, the need for better combustion controls for hog fuel would be evident. It was planned to have these controls installed by the end of 1979. By 1980, emission-control devices (if they are needed) would be selected, based on maximum hog-fuel firing.

Results to date. The most encouraging aspect of the program thus far has been the major reduction in

New burners are installed at Northwood to improve performance

New burners, burner-management system key to retrofit job

Burners. The six new dual-air-zone burners installed on the Northwood power boiler are capable of firing up to 100-million Btu/hr each on either gas or oil, or on both fuels simultaneously, with tighter control of excess air, a better turndown ratio, reduced flameouts, and a higher relight efficiency than was possible with the original equipment. The burners also are capable of adaptation to firing wood fines in suspension.

The dual-air zone permits flame shaping to prevent impingement on boiler tubes, leading to a 10:1 turndown ratio on natural gas, 8:1 on oil. Tight damper shutoff prevents intrusion of tramp air into the boiler via burners not in use. This tight shutoff significantly improves boiler efficiency and allows the firing rate for hog fuel to be substantially increased. Overall, the burners give added operator flexibility, with remote panel control.

Burner management. The state-of-the-art solid-state-logic burner-management system is custom designed to suit specific operating requirements. (It exceeds FM and NFPA requirements.) The ultraviolet flame scanners incorporate a self-checking capability. High system reliability permits a first-try light-off frequency of more than 99%.

particulate discharges from the boiler. When hog-burning rates were initially increased above 240,000 lb/hr, very little could be done, it appeared, to prevent black stack conditions. However, at hog-burning rates now approaching 300,000 lb/hr, boiler emissions are routinely meeting the 0.15-gr/scf permit limit. Two main reasons for this improvement:

- Operator involvement. It was recognized from the start that the operators were the most knowledgeable about boiler problems and that their involvement would be invaluable. They were quite willing to study and attempt to control the variables that affected emissions, especially from burning hog fuel, and experimented on their own.
- Continuous particulate monitor installed on the stack supplied emission data which showed the effect of changes in boiler operation; it also allowed for boiler characterization.

Boiler trial results. Major factors learned from boiler trials to date:

- A straight-line relationship existed between hog fuel consumption and particulate emissions during steady loads. The boiler apparently was capable of meeting the permit limit for particulate emissions under stable conditions, which led to further studies into what variables caused the higher emissions.
- Boiler load swings were found to have a detrimental effect on emissions. Rapid increases in boiler load caused a temporary depletion of excess air, which brought about black stack conditions. The problem does not appear to be difficult to rectify.
- Sootblowing, as well as blowing the grates during the cleaning procedure, resulted in abnormally high particulate emissions. Since the duration of these operations is not long, they can most likely be covered under the permit conditions, which allow a certain period of upset time every 24 hr.
- Loss of hog fuel was found to contribute to high emission rates. As the fuel supply dropped, undergrate air had a tendency to lift the burning bed and cause suspension burning. The problem appears to be simple to eliminate.
- Emissions can be reduced by limiting excess O_2 to the 7% range rather than the normal 10%. Improved instrumentation and control logic needed to maintain the air supply more closely should allow lower levels of excess O_2, perhaps even down to 3 or 4%. ■

Northwood Pulp Ltd, Prince George, B.C.: Principal plant equipment

Steam-generator and auxiliaries

Chemical-recovery boiler, 1 .... Combustion Engineering Inc
428,000 lb/hr at 625 psig/750F, eight gas/oil auxiliary burners
Recovery-boiler electrostatic precipitator, 1 .... Research-Cottrell Inc
Two sections, three fields per section
Recovery-boiler sootblowers, 34 .... Copes-Vulcan Inc
Retractable type
Hogged-fuel boiler, 1 .... Foster Wheeler Canada Ltd
450,000 lb/hr at 640 psig/750F when burning both hogged fuel and gas or oil, 250,000 lb/hr at 640 psig/750F when burning hogged fuel alone on water-cooled pinhole grate (24½ ft × 19½ ft) equipped with steam jets for ash removal, three hogged-fuel feeders deliver wood to six feeder chutes, cinder-reinjection system
Hogged-fuel-boiler burners*, 6 .... Coen Co
Gas/oil capability now, wood fines in future
Hogged-fuel-boiler burner-management system* .... Coen Co
Hogged-fuel-boiler sootblowers, 8 .... Copes-Vulcan Inc
Retractable type
Auxiliary boiler, 1 .... Riley Stoker Corp
120,000 lb/hr at 630 psig/700F
Auxiliary-boiler burner, 1 .... Coen Co
Gas/No. 2 oil

Turbine/generator and auxiliaries

Turbine/generator, 1 .... Stal-Laval Turbin AB
28,000 kW, 640 psig/750F, 80-psig back-pressure, 180-psig extraction steam, balancing condenser designed to handle 100,000 lb/hr of 65-psig steam, 3600 rpm

Condensate and feedwater systems

Pressure filters, 4 ....Graver Water Conditioning Co
8 ft diameter × 5½ ft high, multimedia type (sand and anthracite coal)
Cation-exchange units, 4 ....Graver Water Conditioning Co
8 ft diameter × 8 ft high, 540 gpm
Vacuum degasifer, 1 ....Graver Water Conditioning Co
Anion-exchange units, 4 ....Graver Water Conditioning Co
6½ ft diameter × 6½ ft high, 540 gpm
Condensate polishers, 2 ....Himsley Engineering Ltd
Condensate collected from the mill (65% return) is pumped through a sodium-cycle ion exchanger to the deaerator, each polisher rated 800 gpm at 210-285F
Deaerator, 1 ....Graver Water Conditioning Co
Vertical spray type, 900,000 lb/hr, 45-psig operating pressure

Service-water system

Service-water pumps, 4 ....Johnston Pump Co
Each vertical-lift type, 8200 gpm
Reactor/clarifier, 1 ....Graver Water Conditioning Co
175 ft diameter, 22,200-gpm design flow with 3-hr retention time
Pressure filters, 6 ....Graver Water Conditioning Co
Multimedia type (sand and anthracite coal) complete with air-scour system

Compressed-air system

Air compressor, 1 .... Atlas Copco Inc
1940 cfm at 100 psig
Air compressors, 2 .... Atlas Copco Inc
Each 1940 cfm at 40 psig

*Equipment added during boiler-upgrading program described in article

Mid-size plant puts coordinated effort into energy management and retrofits

Elliott Co's Jeannette plant, expending nearly a trillion Btu/yr, found that it was too big for intuitive and isolated decisions on energy. Organized planning, already paying off, promises optimum returns

By Karen J Lewis, Elliott Co

Like many other manufacturers, Elliott Co has felt the crunch of rising fuel costs and limited fuel supplies. Elliott's plant at Jeannette, Pa, manufactures energy equipment, including air and gas compressors, steam turbines, and gas expanders and turbochargers. Over 550 machine tools, 30 heat-treat furnaces and ovens, testing facilities, and boilers with combined capacities in excess of 225,000 lb/hr occupy about 1-million sq ft of space. The plant employs 2300.

In 1978, energy consumption was nearly 1-trillion Btu for process and nonprocess operation. High fuel costs and certainty of escalation in the future made Elliott realize that a well-organized effort is necessary to ensure efficient use of energy and to reduce overall consumption.

At one time, energy conservation at Elliott had been on an uncoordinated basis. As in other companies, a management-by-crisis attitude had often been the response to fuel-oil embargoes, coal strikes, and natural-gas shortages. For example, during curtailment periods, employees would become conscientious about turning off lights, shutting down equipment not in use, and lowering thermostats—all to ensure fuel for continued plant operation. Unfortunately, once the crisis was past, reversion to old ways occurred.

Adding to the Jeannette plant's problems is its dependence on No. 6 oil and gas. This dates from 1971, when the coal-fired boilers were converted to operate on gas or No. 6 oil, to meet EPA standards and to avoid strike-caused shortages. Conversion was completed just before the 1973 oil embargo.

The energy-conservation effort improved slowly. In 1973, capacitors to improve power factor were installed at the transformers. In 1977, two on-site gas wells were drilled, yielding substantial reserves for backup of regular sources. February 1978 saw startup of a steam-turbine/generator, producing 20% of plant electrical load by steam expansion from 650 psig to the 150-psig level for the plant. The unit is economical to run only in winter months, when need is high for 150-psig nonprocess steam.

In 1977, Elliott also organized a task force of departmental managers to discuss problems, and possible solutions, of increasing plant energy demands, consumption, and costs. The decision was to assign a mechanical engineer as energy coordinator, with full-time responsibility for energy conservation (Fig 3).

A comprehensive energy audit was naturally the first step in a planned

1. Upgraded lighting in the rotor division increased level from 20 to 70 foot-candles while cutting electric use by 50%

2. 600-psig steam traps are high-pressure concern of energy coordinator Lewis. Outside-firm trap survey is now complete

program. Cutoff date for the historical audit was 1975. Records before then were sketchy, and were distorted by such incidents as a long strike and the oil embargo. The audit spotlighted a fairly constant purchased-electric load, with a large drop every July during scheduled shutdowns. Gas and oil usage peaks in the winter months. A second important part of the audit was identification of locations, types, sizes—and interactions—of process and nonprocess equipment.

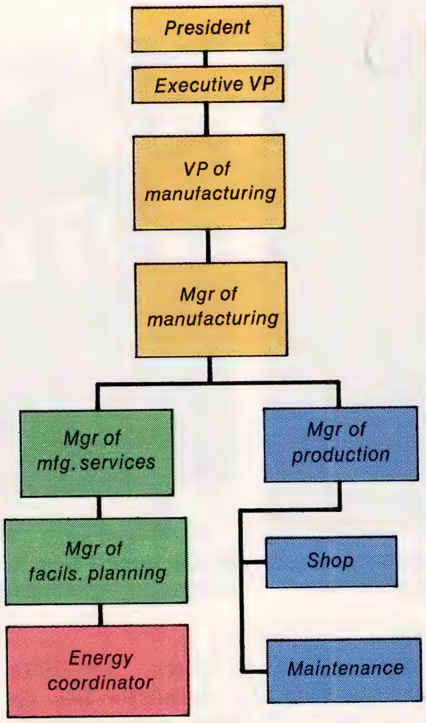
Auditing, having revealed existing conditions, is continuing. Some of the projects completed or planned are intended to make the auditing easier and more significant. For example, the first of the energy projects under the coordinated effort was installation of electric and gas meters to give data in support of future projects.

Production equipment audited was chiefly the boilers, heat-treating equipment (gas-fired and electric), machine tools, and testing facilities.

Testing facilities were an important part of audited equipment. Elliott's products are specialized and engineered according to customers' requests and specifications. Compressors may have steam or motor drive. Fortunately, all steam from test-drive turbines exhausts into a condenser, and the condensate is pumped back to the boilers. Only a small amount of steam exhausts to atmosphere, from the ejector system for casing evacuation and condenser vacuum pumps.

Preparation for a coordinated energy-conservation program includes state-of-the-art training for the program leader. Seminars, courses, and visits to equipment manufacturers, nearby plants, and industry exhibitions are important. Elliott's experience with seminars indicates:

- A seminar presented to a group of attendees with similar backgrounds—either industrial, commercial, or institutional—is more likely to be worthwhile.
- A seminar that has been repeated several times may be more valuable than a first-time performance, because feedback and experience build as presentations are repeated.
- Discussions with fellow participants is valuable.
- Doubts about whether a seminar is worthwhile for a plant can be cleared up by talking to those who have attended. Ask the seminar sponsor for names.



3. Manufacturing oversees energy usage in decentralized setup such as Elliott's

Background for a coordinator

Assignments in manufacturing, engineering, and marketing spanning 90 weeks were the basic experience that gave a thorough grounding in the nature of the Jeannette operations. Intimate knowledge of a plant's physical facilities is an invaluable byproduct of this type of training and is essential to effective energy coordination for a large energy user.

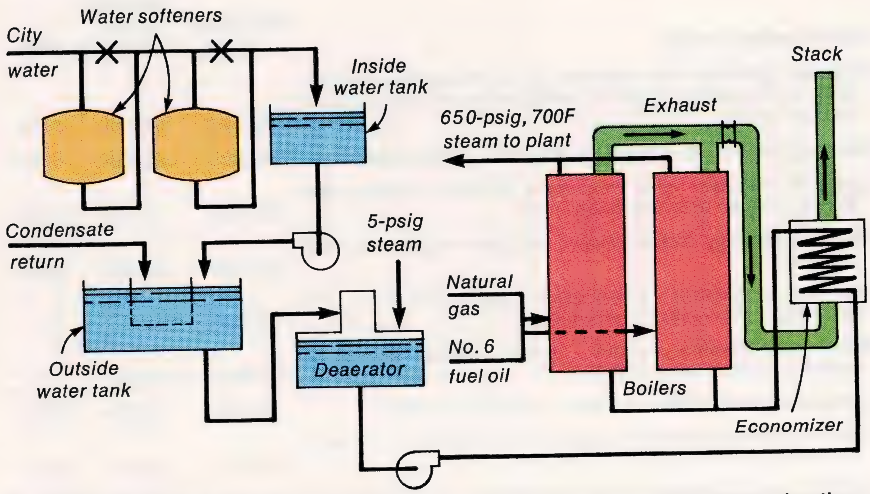
The training period included 'hands-on' experience on lathes, milling machines, drill presses, and grinders, followed by 13 weeks of foreman duties in machining, assembly, and test. QA projects and work in manufacturing services were next. Design and test engineering projects, over 31 weeks, included compressor-design tasks, rotor-balancing instruction writing, compressor tests, and performance evaluation. After the training program, work in the manufacturing services/facilities planning department at Elliott led to Karen Lewis's present position as energy coordinator for Elliott's divisions.

Tracking down the ECO

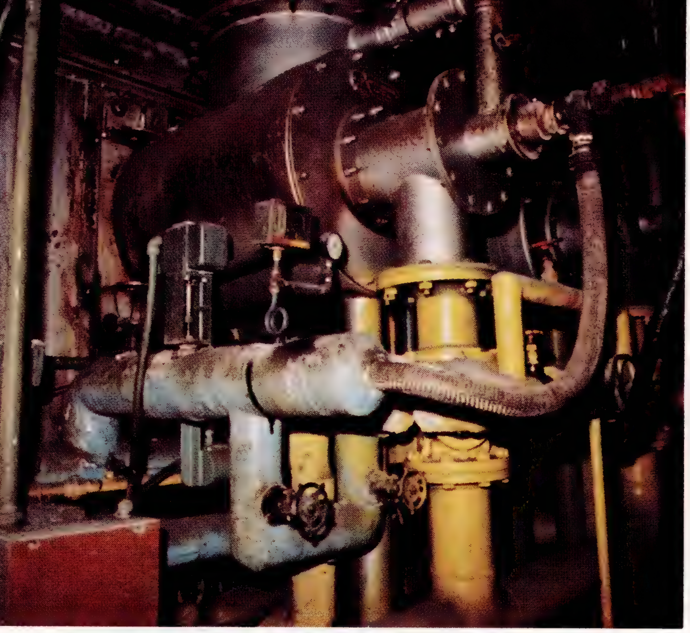
Energy-conservation opportunities (ECO), judged from the standpoint of the energy audit, can sometimes require considerable capital outlay. Others are easy to implement without spending capital. And some others, although not bringing direct, tangible money savings, may help establish a successful program.

Doing more production and equipment testing in off shifts will reduce electric demand during peak hours. Staggered startup of equipment also may lower peak demand. Meters on new or retrofitted equipment will reveal usage. And, finally an energy-awareness program for employees is important, because they are the ones who will be implementing changes.

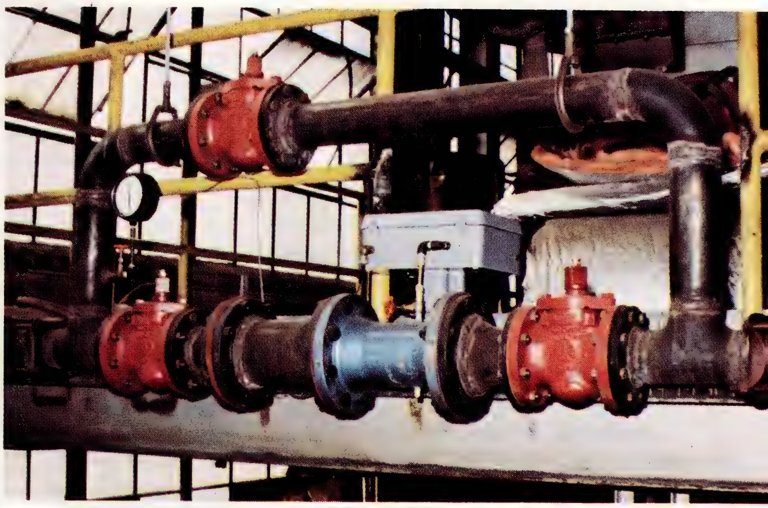
An employee suggestion program at Jeannette, with ideas sent for evaluation on a monthly basis to an energy-conservation committee, has produced several inexpensively implemented projects. Benefits and



4. Steam system at Jeannette centers on two 70,000-lb/hr boilers. Feedwater heating is by boiler-feed turbine exhaust and flashtank for blowdown and high-pressure traps



5. Dual-fuel system burners allow plant the flexibility to burn either natural gas or No. 6 fuel oil in its steam generators



6. Gas meters, such as this one on line to boilers, give data for continuous departmental audit of energy consumption

prizes, based on savings, help to stimulate suggestions. The head of the Jeannette committee oversees similar programs at Elliott's plants in Donora and Scranton, Pa, with plans for expanding to the Springfield and Dayton (Ohio) plants and to a plant in Cowes, England.

Lighting upgrading is in progress (Fig 1). In most cases, the new lamps give higher lighting levels. The high-pressure sodium-vapor lamp (125 lumens/W) is superior to mercury-vapor (63 lumens/W) and fluorescent (78 lumens/W).

The steam-distribution system is one of the largest potential sources of savings; however, steam-trap maintenance is crucial to these savings (Fig 2). Jeannette has an estimated 550 traps, with pressures from 10 to 650 psig. An in-plant survey by an experienced specialist firm located and tagged all the steam traps, and found a 30% steam loss because of faulty traps.

Proper trap maintenance will reduce steam loss to 3%. A regular schedule will include systematic check, followed by repair on a stated priority basis. All retrofitted traps will have valves on both inlet and outlet lines. An added intangible benefit of good trap maintenance is elimination of potentially hazardous steam in drains.

Recuperators on the larger heat-treating furnaces will preheat intake air with flue-gas waste heat. One furnace operates at 1100F for 16 hr/day. Preheating its intake air to 600F, instead of allowing entry at ambient temperature, will save at least 10% in fuel, and will give a payback in less than three years.

The boilers (Figs 4-6) are the largest in-house energy consumers. Numerous projects have been initiated to save energy, including installation of economizer tubes. Automatic fuel/air-ratio controls for the boilers also appear worthwhile, to maintain boiler excess air levels at 20% for fuel oil and 10% for natural gas, an improvement over the existing manual control that holds about 30% excess air. Automatic blowdown systems are now being installed, too.

Smaller projects are constantly under way, too. Insulation of pickling tanks is an example. This recently completed project involved covering acid, alkali, rust-inhibitor, and water tanks with 2-in. foamglass block insulation, and installing removable lids on all tanks. The work will not only cut heat loss but also help maintain solution temperatures. The tanks can be shut off over weekends without requiring a three-day reheat.

All in all, Elliott's program, with most projects giving payback in less than two years, has started successfully. And complete support and commitment from all levels of organization is clear. ■

High return for moderate expense is keynote

Planned energy projects	Estimated cost, $	Estimated annual savings, $	ROI[1]
Upgrade lighting—replacement of incandescent, fluorescent, and mercury vapor by metal halide or high-pressure sodium vapor	50,000	20,000	0.30
Building insulation—block up windows, reduce heat loss	50,000	20,000	0.30
Upgrade furnaces and heat-treat ovens—improve efficiency, reduce or reuse waste heat	35,000	15,000	0.33
Electrical-energy management system—automatic load shedding	100,000	45,000	0.35
Metering equipment—install electric and gas meters on all large energy-consuming equipment	25,000	—	—
Steam-distribution system—repair, replace, update, maintain steam traps and lines	40,000	250,000	>1
Compressed-air system—repair, update, maintain	40,000	40,000	0.90
Miscellaneous projects—ideas from employees through the energy-conservation committee	25,000	20,000	0.70

[1]ROI (return on investment) calculated as: (annual savings − annual depreciation)/cost

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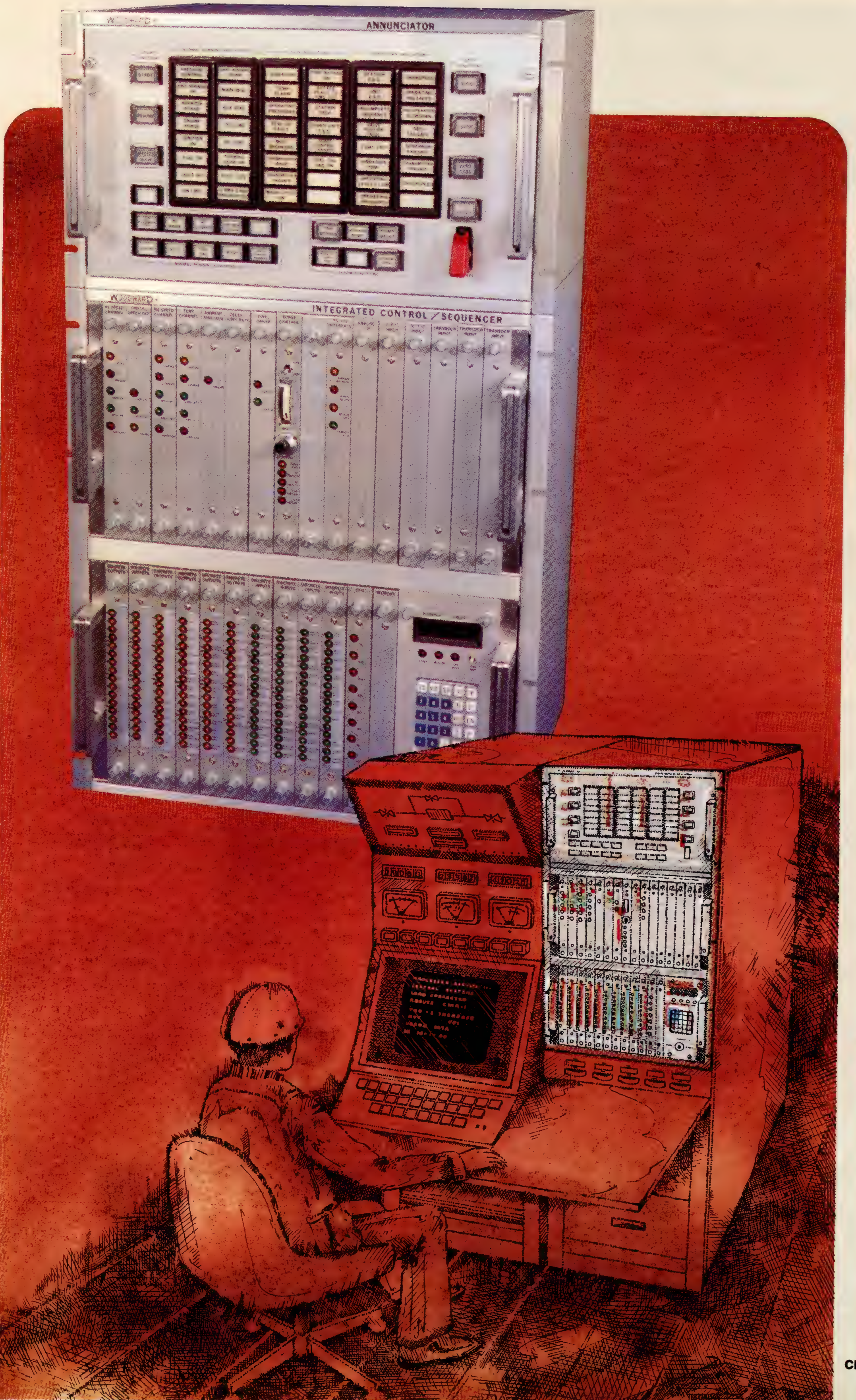

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COGENERATION

OVERVIEW

Cogeneration: Has its time come?

As a result of power-market conditions that have developed since the 1973 oil embargo set in motion a sharp upward trend in primary power costs, US industry has been showing increasing interest in the cogeneration of electricity and process heat for industrial requirements.

However, the strong position of the electric utilities, which have continued to offer electricity at an attractive price, has produced a situation in which cogeneration of heat and power is much less widespread here than in other industrial countries. Power produced by German industry, for example, amounts to 29% of the country's total consumption, compared to only 5% in the US today—and that is down from 15% in 1950.

For cogeneration to become a significant form of power generation, it must overcome barriers due to fuel supply and price uncertainties, technological risks, marginal economics, environmental controls, and fear by industry of increased government regulation.

Established industry traditions, practices, and perceptions also present problems that must be overcome. The average plant perceives its connection from the local electric utility to be a reliable energy source that is not subject to allocation or environmental controls. Typically, industrial plants do not have power-plant personnel, nor do they wish to deal with the complexities of grid load management based on regulatory considerations. Reliability problems of power-plant equipment represent risks to production. And the option of investing capital to produce a commodity that is, for the most part, easily purchased is not viewed with favor.

Despite these obstacles, many small cogeneration systems are now operating, but they only scratch the surface of this sleeping giant. DOE leadership is crucial to fulfilling cogeneration's potential for energy conservation, estimated to be about 15,000 MW by 1985. A DOE-sponsored study, the Cogeneration Technology Alternative Study, assesses the best emerging technologies for cogeneration in energy-intensive industries.

Needless to say, economic and environmental legislation will have a big effect on the economics of cogeneration. The latest word from Washington comes from the Federal Energy Regulatory Commission which has just released its first policy paper on cogeneration.

Among the major proposed policy points:

- Authority must be available to mandate interconnections between cogenerators and utilities.
- Rules will have to apply to retail as well as wholesale sales of power, necessitating a "fundamental reordering of the traditional dual regulatory scheme."
- Price of the power supplied by a cogenerator would be based, for the first time, on the "buyer's avoided cost," rather than the cost of supplying the power.
- Traditional "split-savings" rates for power bought and sold could be tilted to make cogenerators realize more of the savings than the utilities.
- Cogenerators would not be held to a minimum reliability standard, though those with lower reliability would have to sell power at a lower price.
- Cogenerators could be exempted from state and federal utility regulations.
- Utilities may be required to treat cogenerators in the same way as similar noncogenerating industrials for the purposes of backup rates and other services.

In this section, you will see how Kerr-McGee Chemical Corp cogenerates without a utility intertie, how Lihue plantation uses a waste product—bagasse—to cogenerate with a utility supplying backup power, and how an industrial park might be set up to supply power, heat, and fuel to various concerns.

Cogenerating without a utility intertie

The first large coal-fired industrial power plant in California provides electric power and process steam for Kerr-McGee Chemical Corp's new Argus facility—a 1.3-million-ton/yr soda-ash plant at Trona. This cogeneration plant was completed and went on line in mid-1978. Construction took some 2½ years.

The new plant is adjacent to existing operations at Trona, where triple-effect evaporators concentrate mineral-rich brine from nearby Searles Lake for the production of borax, potash, and sodium-sulfate products.

Ralph M Parsons Co was prime contractor for the project, including the power plant, which uses two 27.5-MW single-automatic-extraction, noncondensing steam turbines. Steam for the turbines is generated by two 600,000-lb/hr, 1500-psig pulverized-coal-fired boilers, which are presently burning low-sulfur New Mexico coal and petroleum coke. Some 85-90% of the heat generated is used for process, the remainder for electricity.

Coal and coke handling. One headache inherent in any coal-fired power plant is the materials-handling system. Keep in mind that what works best with one coal will not necessarily work with a different one. The only way you can be sure a design is adequate is to test your coal on an existing system similar to yours.

At Trona, coke and coal are delivered by unit trains, with about 6500 tons per trainload. Each car is dumped into two below-grade track hoppers. Belt feeders direct the coal or coke to a secondary belt conveyor, which transports it to a main conveyor that moves the coal or coke to their respective storage areas through a dust-control tower.

A 15,000-ton live coal pile (Fig 1) and a 5000-ton live coke pile are maintained near the dust tower, with excess coal and coke stockpiled in a dead-storage area.

1. Belt conveyor moves coal to live pile. New Argus facility is at left

Fuel is reclaimed from storage by front-end loaders and delivered to reclaim hoppers. A reclaim conveyor then feeds the materials to the crusher, and on to six 360-ton coal/coke closed silos equipped with individual gates (Fig 2). Dust suppression at transfer points in the coal-handling system is handled with a chemical spray.

Engineers at Kerr-McGee urge flexibility in thinking when designing a coal-handling system. The idea for the closed silos came from observing a cement operation. Also, look carefully at bins and silos with respect to slopes and finishes, in order to avoid sticking problems.

Boiler details. The two tangentially fired drum-type, balanced-draft, nonreheat boilers, which produce 955F steam, are equipped with oversized furnaces, and use overfire air to maintain a lower flame temperature, in order to meet NO_x emission standards. The flue-gas mass flow is approximately 1-million lb/hr.

Three burner levels of coal are provided in each of the boiler's four corner windboxes. Gas-fired ignitors, gas guns, oil guns, and flame scanners are located in all four corners between all coal levels. Each boiler burns about 35 tons/hr of coal.

The boilers are designed to be able to burn gas, oil, and petroleum coke, as well as coal, either singly or in combination.

Depending upon process and electric demands, steam is either extracted at 450 psig part way through the cycle, to a medium-pressure header, or passes completely through the turbine and is exhausted at 40 psig to a low-pressure process-steam header. The latter is used mainly for the evaporators and heat exchangers which condense the steam.

In addition to the new Argus plant, there are several older noncondensing steam-turbine/generators at the adjacent Trona plant, with small gas/oil-fired boilers producing steam at several pressure levels—650, 450, and 250 psig. Fig 3 shows a simplified cycle diagram for both the new Argus plant and the existing Trona facility.

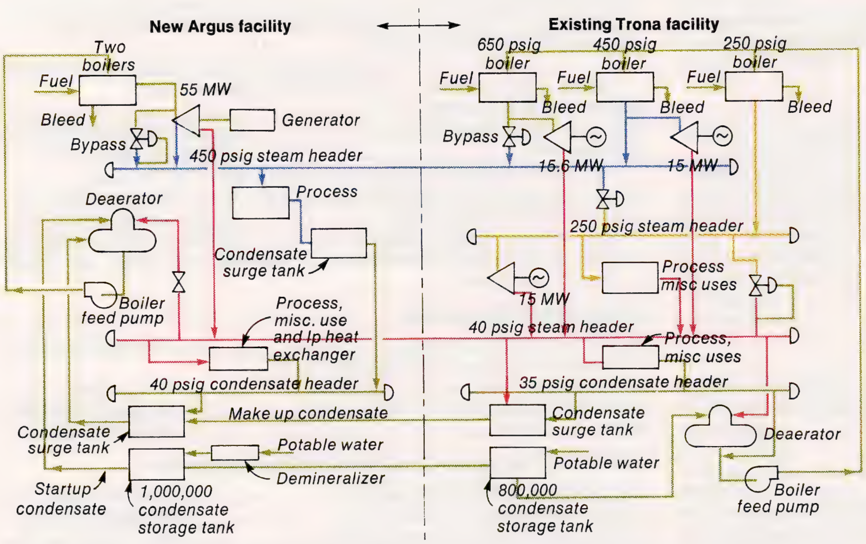
Flexibility has been built into the system, so that any boiler can feed any turbine should the need arise. Since relative fuel costs favor the new coal-fired units, the existing Trona generators are primarily used for load swings and as backup, should one of the new turbine/generators trip or be down for maintenance.

The two plants are tied together by two common steam-header systems and several condensate lines. Condensate from various processes is collected in local surge tanks and pumped to a main-plant condensate surge tank. This condensate, at 40 psig (saturated), is delivered to the new boilers by turbine-driven boiler-feed pumps.

Designers opted for steam-driven auxiliaries for maximum dependability, and because the facilities are not interconnected to a utility grid. The

2. Six closed coal/coke silos ensure minimum dust leakage

4. Ash-handling system saves water. Flyash is handled dry



3. Steam header and condensate return and makeup systems serve entire plant

forced- and induced-draft fans, as well as the boiler-feed pumps, have turbine drives (see equipment list at the end of this article).

A combustion-control system automatically controls the fuel, air, and feedwater inputs to the new boilers. Also, a flame-safety system precludes boiler explosion. Two data loggers—one for the process and one for the utility systems—monitor about 700 points in each system. In addition, all plant motors are operated from the control room via two-wire control systems.

Tight control of air pollution. Searles Lake is near the northern boundary of San Bernardino County, which makes it subject to the tough air-pollution regulations of the San Bernardino County Desert Air Pollution Control District. Each boiler may release no more than 16 lb/hr of particulates, 200 lb/hr of sulfur as SO_2, or 450 ppm, corrected to 3% O_2 of NO_x.

Each boiler is equipped with a regenerative air preheater, followed by an electrostatic precipitator, rated at 99.8% efficiency, and a sodium carbonate flue-gas wet scrubber rated at 88%. The precipitators operate on the cold side of the boiler air preheaters. Hot-side precipitators could not guarantee compliance with pollution regulations, due to the larger volumes of flue gas at the higher hot-side temperatures.

However, the 300F temperature on the cold side makes it difficult to collect flyash. The western coal that is used has a sulfur content of only 0.5% and particle ionization at 300F is insufficient for efficient collection of flyash by the precipitators. So petroleum coke is mixed with the coal to raise the sulfur content to 1.5% and improve particle ionization and flyash collection.

The two flue-gas scrubbers use end liquor from the soda-ash plant to extract CO_2, and are designed to operate in the sulfite/sulfate range. Scrubber liquor is returned to Searles Lake along with the rest of the plant's end liquor.

Flows stay soluble throughout the scrubber, thus eliminating any potential scale buildup. Moreover, the scrubbers cannot be bypassed, emphasizing the need for cleanliness and reliability.

Scrubbed flue gases are processed through two monoethanolamine (MEA) plants for extraction of CO_2. Each plant produces 300 tons/day of CO_2—the main source of makeup CO_2 in the closed-cycle system. Liquid CO_2 is stored for plant startup and for use in emergencies.

Water conservation is an important feature of the entire operation. The Trona main-plant cycle is a net producer of fresh water from brine through its triple-effect evaporators. The water produced is fed to the power-plant boilers, along with condensate from the process dryers. Steam condensate is returned to the process in the closed-cycle system. In addition, potable water is pumped to the soda-ash plant from wells 25 miles away. ■

Kerr-McGee Chemical Corp, Trona, Calif: Principal plant equipment

Steam generator and auxiliaries

Steam generators, 2 ... Combustion Engineering Inc
Each 600,000 lb/hr of 1515-psig/955F steam, superheat temperature control by burner tilt and condensate spray, balanced draft, 13,452-sq ft waterwall surface, 4676/14,588-sq ft superheater (platen/spaced) surface, 11,700-sq ft economizer surface, 77,400-sq ft air-heater surface, 60,900-cu ft furnace volume
Combustion-control system ... Foxboro Co
Burner assemblies, 4 per boiler ... Combustion Engineering Inc
Located in the four corners of the furnace; each assembly provides for three levels of coal firing, two for oil firing, two for gas, and includes two flame scanners and igniters
Atomizing-steam desuperheaters ... Forney Engineering Co
Pulverizers, 3 per boiler .. Combustion Engineering Inc, Raymond Div
Each 13 tons/hr, 300-hp motor drive
Forced-draft fan, 1 per boiler. . . .
. . . .Westinghouse Electric Corp, Sturtevant Div
266,000 cfm of 115F air at 18.2 in. H_2O, inlet-vane flow control
Forced-draft-fan turbine drive, 1 per boiler ... Terry Corp
Induced-draft fan, 1 per boiler ... Buffalo Forge Co
396,000 cfm of 363F flue gas at 19 in. H_2O
Induced-draft-fan turbine drive, 1 per boiler ... Elliott Co
Regenerative air preheaters ... Air Preheater Co
Bottom-ash handling system ... Allen-Sherman-Hoff Co
Includes hoppers, ejectors, ash crushers, etc
Bottom-ash chemical-control system ... Allen-Sherman-Hoff Co
Low-pressure ash-water pumps ... Duriron Co
High-pressure ash-water pumps ... Barrett, Haentjens & Co
Bottom-ash sump pumps ... Barrett, Haentjens & Co
Boiler-blowdown tank ... Grand Steel Corp

Turbine/generators and auxiliaries

Turbine/generators, 2 ... General Electric Co
Each 27 MW, one 450-psig bleed point, 40-psig back-pressure
Turbine-bypass desuperheater ... Forney Engineering Co
Turbine-room crane ... Crane Hoist Engineering Co
Monorail hoists and trolleys ... Allis Chalmers Corp
Main-turbine flash tank ... Grand Steel Corp
Turbine-building flash tank ... Grand Steel Corp
Lube-oil transfer pump ... Gilbarco Inc, Sier-Bath Pump Div
Clean lube-oil storage tank ... Hopper Inc
Dirty lube-oil storage tank ... Hopper Inc

Condensate and feedwater systems

Condensate receiver ... Grand Steel Corp
Condensate storage tank ... Cyprus Specialty Steel Co
Condensate pumps ... Duriron Co
Condensate-makeup pumps ... Duriron Co
Condensate transfer pump ... Duriron Co
Condenste flash drum (oil system) ... Grand Steel Corp
Deaerator ... Chromalloy American Co, LA/Water Treatment Div
Deaerator desuperheater ... Forney Engineering Co
First-effect condensate surge tank ... Grand Steel Corp
Evaporator condensate pumps ... FMC Corp, Peerless Pump Div
10-psig flash tank ... Alameda Tank Co
10-psig flash drum ... Grand Steel Corp
10-psig steam desuperheater ... Forney Engineering Co
10-psig condensate receiver ... Grand Steel Corp
10-psig condensate-return pumps ... FMC Corp, Peerless Pump Div
40-psig flash-drum condensate pumps. . . .
. . . .FMC Corp, Peerless Pump Div
40-psig condensate pumps ... Duriron Co
Desuperheater water pump ... Bingham-Willamette Co
Phosphate-solution tank ... Chas P Crowley Co
Phosphate-solution injection pumps ... Chas P Crowley Co
Hydrazine-solution tank ... Chas P Crowley Co
Hydrazine-solution injection pumps ... Chas P Crowley Co
Dealkalizer ... Chromalloy American Co, LA/Water Treatment Div
Dealkalizer-effluent holding tank ... Tankinetics Inc
Dealkalizer holding-tank pump ... Duriron Co
Demineralizer ... Chromalloy American Co, LA/Water Treatment Co
Demineralizer-effluent holding tank ... Tankinetics Inc
Sodium-hydroxide transfer pump .. Gilbarco Inc, Sier-Bath Pump Div
Sulfuric-acid transfer pump ... Gilbarco Inc, Sier-Bath Pump Div
Boiler-feed pumps, 3 ... Bingham-Willamette Co
One 2500-hp steam-turbine-driven pump per boiler delivering 1471 gpm at 2029 psig and one 2500-hp motor-driven pump serving as a common standby
Boiler-feed-pump turbine drives, 1 per boiler ... Turbodyne Corp
Feedwater-control system ... Foxboro Co

Fuel-oil system

Fuel-oil day tank ... Cyprus Specialty Steel Co
Fuel-oil heater ... Weigmann & Rose Co
Fuel-oil-heater desuperheater ... Forney Engineering Co
Main fuel-oil pumps ... Gilbarco Inc, Sier-Bath Pump Div
Circulating fuel-oil pumps ... Gilbarco Inc, Sier-Bath Pump Div
Fuel-oil filters ... Facet Enterprises Inc

Coal-handling system

Dust-suppression system ... Johnson March Corp
Railroad-car shaker ... Allis Chalmers Corp
Track unloading hopper ... Pittsburgh-DesMoines Steel Co
Belt scale ... Auto Weigh Inc
Tramp-iron magnet ... Eriez Magnetics
Electronic metal detector ... Oretronics Inc
Crusher ... Pennsylvania Crusher Corp
Crusher chute with flop gate ... St. George Steel Fabrication Inc
Coal and coke silo ... Cyprus Specialty Steel Corp
Silo feed gate ... Rise-Louise Corp
Drag link conveyor ... Rise-Louise Corp
Reclaim and surge hoppers ... Pittsburgh-DesMoines Steel Co
Vibrating feeders ... Carmen Industries Inc
Conveyor, feeder, and hopper chutes. . . .
. . . .St. George Steel Fabrication Inc

Pollution-control systems

Chimney ... Francis Hankin & Co
200 ft, concrete
Electrostatic precipitator ... C-E Walther Inc
Flyash handling system ... Allen-Sherman-Hoff Co
Includes ash storage silo, secondary fabric filter, eductors, etc
Sulfur-dioxide removal system. . . .
. . . .Combustion Equipment Associates Inc
Alkaline-liquor (sodium carbonate) absorption system
Scrubber-liquor pumps ... Duriron Co
Scrubber-liquor storage tank ... Cyprus Specialty Steel Co
Cooling tower ... Marley Cooling Tower Co
Four cells, crossflow type, uses brackish water for cooling
Brackish-water distribution pumps ... FMC Corp, Peerless Pump Div
Brackish-water storage tank ... Cyprus Specialty Steel Co
Cooling-water treatment system ... Marley Coolng Tower Co
Includes chromate storage tank, chromate day tank, chromate injection pump, etc

Compressed-air system

Instrument-air compressors ... Joy Manufacturing Co
One motor-driven, one turbine-driven
Instrument-air receiver ... Grand Steel Corp
Instrument-air-compressor aftercooler ... Joy Manufacturing Co
Plant-air receiver ... Grand Steel Corp

Miscellaneous pumps and mechanical equipment

Central-plant water-chiller package ... Dunham-Bush Inc
Chilled-water expansion tank ... Grand Steel Corp
Chilled-water chemical-feed system ... Nalco Chemical Co
Chilled-water circulating pump ... Duriron Co
Water-softening system
Chromalloy American Co, LA/Water Treatment Div
Softened-water storage tank ... Cyprus Specialty Steel Co
Softened-water distribution pump ... FMC Corp, Peerless Pump Div
Cooling-water circulating pumps ... Johnston Pump Co
Potable-water booster pumps ... FMC Corp, Peerless Pump Div
Fire-water pumps ... Allis Chalmers Corp
Fire-water jockey pump ... Duriron Co
Sump pumps ... Crane Co, Deming Div

Electrical equipment

Tie-line power transformers ... Westinghouse Electric Corp
Tie-line control panel and auxiliary cabinet ... Hatch Inc
Medium-voltage switchgear ... Gould Inc, ITE Imperial Div
Medium-voltage transformers ... Westinghouse Electric Corp
Medium-voltage motor-control centers ... Westinghouse Electric Corp
Low-voltage switchgear ... General Electric Co
Low-voltage transformers ... Westinghouse Electric Corp
2300-480V transformers ... Westinghouse Electric Corp
6900-480V transformers ... Westinghouse Electric Corp
480-V motor-control centers ... Westinghouse Electric Corp
5-kV system grounding equipment ... Gould Inc, ITE Imperial Div
5-kV system bus duct ... Gould Inc, ITE Imperial Div
7.2-kV switchgear accessories ... General Electric Co
15-kV system bus duct ... Gould Inc, ITE Imperial Div
15-kV neutral grounding resistor ... General Electric Co
125-V station battery ... Eltra Corp, C&D Batteries Div
Battery charger ... Eltra Corp, C&D Batteries Div
Battery panel ... Federal Pacific Electric Co
125-V dc/125-V ac inverter ... Exide Power Systems Div
125-V dc power distribution panel ... Federal Pacific Electric Co

Cogeneration cuts utility's kW cost

An unusual partnership in financing, building, operating, and using the energy from a bagasse-fueled cogeneration power plant in Hawaii may encourage similar arrangements with projects of this type

By John Brown, Foster Wheeler Kauai Inc

A $25-million, 20-MW cogeneration power plant is being built on the island of Kauai, Hawaii, which will burn bagasse and oil with provisions for future burning of cane trash and prepared municipal refuse. Steam and electric power will be used by a sugar factory; power in excess of the factory's needs will be sold to the island's utility (see box).

The cogeneration project is unusual in that Foster Wheeler Kauai Inc (FWKI) is the owner of the new power plant, which Lihue Plantation Co will manage. Lihue's present power facilities consist of several old bagasse-burning boilers and associated generation equipment, all of which require extensive maintenance. FWKI will derive its revenues from the sale of the excess power (roughly 12 MW) to Kauai Electric Co. This arrangement is advantageous to all three project participants.

Specifically, FWKI will have a guaranteed income from the sale of power, which will help to smooth cyclical nature of the parent company's equipment sales to the electric-utility industry. Lihue Plantation will have a new, efficient power-generating facility to replace existing obsolete equipment without major capital investment at a time when the sugar industry is only marginally profitable. Kauai Electric will receive electric power without the need for capital investment in new facilities, which will help to slow the rise in electric energy costs on Kauai, which are among the highest in the nation.

Additionally, the state of Hawaii will benefit from a reduction in oil imports and a power plant emitting a minimum amount of pollutants. The plant will incorporate both a mechanical dust collector and a wet scrubbing system.

Major Lihue participants

- Foster Wheeler Kauai Inc (FWKI) is a wholly owned subsidiary of Foster Wheeler Corp and owner/builder of the power plant.
- Lihue Plantation Co is a wholly owned subsidiary of AMFAC Inc. The power plant will be located at Lihue's sugar factory on Kauai. Lihue will provide fuel, operate, and maintain the plant.
- Kauai Electric Co is a division of Citizens Utilities Co and is the only utility on Kauai. It will buy excess power from Lihue.

Power plant description

The water and steam cycle is a simple conventional power-plant cycle. The boiler selected is rated at 320,500 lb/hr, 850 psig, and 830F firing bagasse. Steam flows to a double-automatic-extraction condensing turbine which drives a 20-MW (nominal) generator. Extraction-steam pressure is 160 psig (550F) and 15 psig (saturated) for sugar factory and power-plant auxiliary requirements. If the turbine is out of service, pressure-reducing stations and desuperheaters are provided from the main steam line to the 160-psig extraction line and from the 160-psig line to the 15-psig extraction line for use in the sugar factory processes (see figure).

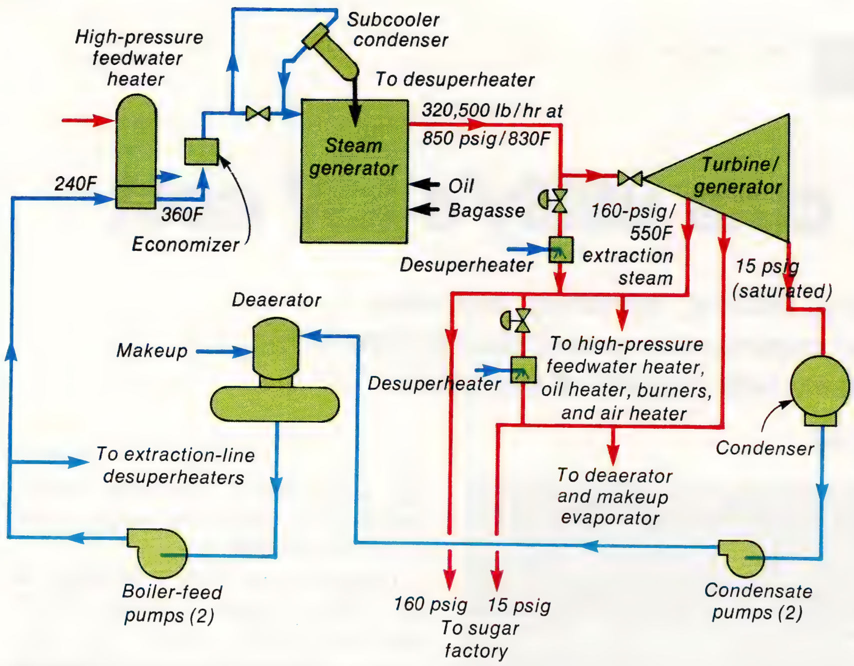
Steam discharging from the turbine is condensed in a surface condenser using a once-through cooling-water system. Two full-size (100%) condensate pumps direct the condensate to a deaerator and storage tank, which provides suction head for two boiler-feed pumps rated at 100% and 60%.

Feedwater at 240F is pumped to the boiler through a single vertical feedwater heater, which raises the water temperature entering the economizer to 360F. Steam for the feedwater heater, fuel-oil heater, steam-coil air heater, and for oil atomizing is available from the 160-psig extraction line. Extraction steam at 15 psig is provided for the deaerator and makeup evaporator. All cycle makeup is channeled to the deaerator.

During the grinding season, feedwater makeup is supplied from the evaporators in the sugar plant, which is monitored for impurities prior to pumping to the deaerator. A conventional makeup system tied to condensate storage tanks and new pumps is used as a backup. During the off-season, the makeup evaporator will provide makeup, using service water for supply to the evaporator.

The boiler is designed to supply steam not exceeding 1-ppm total solids. Desuperheater spray water from a subcooler condenser eliminates carryover of any impurities in the feedwater (which is normally used for spray water in utility boilers). Chemical treatment consists of (1) a phosphate/caustic system for pH control and scale prevention, (2) hydrazine for oxygen removal, and (3) filming amine injection into the main steam line for corrosion protection of the low-pressure end to the turbine where condensing occurs.

Fibrous fuel. Bagasse is a woody fibrous fuel, the waste product of the cane-crushing process. About 250,000 tons are produced yearly at Lihue. Depending on local weather



Double-automatic-extraction condensing turbine drives a 20-MW generator

conditions when the cane is harvested, measurable quantities of mud, sand, and rocks are carried through the crushing process and end up in the bagasse fuel. These extraneous materials make up most of the so-called "ash" trapped by the hoppers, dust collector, and scrubber. The bagasse itself produces only about 2% ash.

Bagasse contains between 45 and 50% moisture and, as-fired, has a heating value of about 4000 Btu/lb.

The Lihue boiler is also designed for future burning of cane trash and prepared municipal refuse. Cane trash is the leafy waste produced from the cane-preparation system prior to crushing. At 50% moisture, cane trash has a heating value of about 3700 Btu/lb. Kauai County has received federal, state, and county funds to study the preparation of municipal refuse for burning. Expectations are that refuse with a heating value of 3800 Btu/lb will be delivered to Lihue for burning.

Fuel, air, and gas. The boiler is designed (1) for rated output when burning bagasse or a combination of bagasse and oil, and (2) for reduced capacity when burning oil only.

Bagasse is supplied from an existing bagasse house by new conveyors to six rotary feeders, each of which supplies one of six pneumatic distributors located in the front wall of the furnace. The distributors spread the bagasse onto a traveling grate. The system is designed for full-load operation with only five distributors in service.

An overfire-air system served by a dedicated fan improves combustion. Either No. 2 or 6 oil is supplied from existing tanks through new heating and pumping equipment to three air- or steam-atomizing burners. When burning oil alone, the boiler can produce up to 200,000 lb/hr of steam with two burners in operation. Combination firing of bagasse and oil (at full boiler capacity) is also envisioned.

The boiler is of the balanced-draft type. Combustion air is provided by a single forced-draft (FD) fan through a steam-coil air heater and a tubular air heater and is directed to the oil burner windbox located in the rear wall of the furnace and to the plenum beneath the traveling grate. Air flow is controlled by maintaining a constant pressure downstream of the tubular air heater.

Flue gas flows from the furnace through the pendant superheater section, the boiler bank, economizer, and tubular air heater into a mechanical dust collector (80% efficiency). To conserve energy, the FD fan has high- and low-speed motors, and the induced-draft (ID) fan is driven by a variable-speed dc motor which has a small ac motor backup with an inlet-damper control.

Environmental protection. The plant was initially designed for a mechanical dust collector with a hopper evacuation system. which alone would have satisfied EPA requirements of 20% opacity and a dust loading of 0.4 lb per 100 lb of bagasse. To obtain an environmental permit for the project, however, it was necessary to assure "best available control technology," so a wet scrubber is being paired with the mechanical dust collector, The hopper-evacuation system was eliminated in the new arrangement. Since bagasse contains only about 2% ash, this combination system will lead to low visible emissions for the plant, which is situated on the edge of the town of Lihue.

Due to the seasonal nature of the sugar cane growing/grinding cycle, oil must be burned alone for about 45 days each year. To meet environmental restriction at these times, the boiler's continuous capacity is limited to 164,000 lb/hr. Sulfur content is limited to 0.5 of total fuel burned (bagasse and oil) on a monthly average basis during the grinding season, or 2%-sulfur oil when it is burned alone.

During the off-season, the sulfur content of the oil burned is limited to 0.5%. This means that No. 6 oil may be burned during the grinding season, but No. 2 oil must be burned during the off-season. Bagasse contains no sulfur.

The grinding season is defined as the period during which cane is being ground and sugar produced. At Lihue, this is 9½ months of the year. To satisfy the requirements of Kauai Electric, the plant must produce power for 11 months of the year, with one month set aside for maintenance.

Power distribution system. Electrical power is generated at 13.8 kV. To satisfy the purchased-power agreement, it is necessary to produce salable power of about 6800 kWh. Voltage is stepped up to 57/69 kV for delivery to the utility grid. A tie-line controller (remote dispatching unit) is included to allow the utility to control Lihue output.

The Lihue plant can operate independently of the utility grid system. Station service transformers supply power at 480 V for major plant auxiliary equipment, boiler-feed-pump motors, fan motors, etc, and for other sugar plant auxiliaries. ■

Making cogeneration more attractive

Steam, power, and fuel gas from one source—here's another option to consider when trying to meet the energy supply challenge in new industrial parks, or to retrofit applications in existing plants

By R A Ashworth, Davy Powergas Inc

Coal gasification can be used to supply not only steam and power to an industrial park (the traditional cogeneration concept), but fuel gas as well. To present this so-called cogeneration "plus" concept, Davy Powergas Inc engineers arbitrarily selected a site for the industrial park close to Billings, Mont, an area that has relatively inexpensive, low-sulfur coal close at hand. They also assumed that the industrial users in the park would be able to receive and use the energy in the form provided from the coal-gasification plant; that is, plant output, rather than the end users, dictates energy-output requirements.

This type of coal-gasification facility could be designed to supply almost any end-user energy mix—fuel gas, steam, and power—merely by the addition of offsite steam boilers and turbine/generators. Davy chose a Winkler fluidized-bed coal-gasification plant for its hypothetical application. From an overall thermal efficiency standpoint, the energy mix developed probably represents the optimum or near optimum mix for low-pressure fluidized-bed gasifiers.

Key selections. As mined, western subbituminous coals and lignites characteristically yield a large proportion of fines—roughly 50% of the coal is ½ in. or less. Unless one can use the fines elsewhere, or is willing to pay a premium for sized coal, the selection of a fixed-bed gasifier is not recommended because a specific coal size range is required.

Entrained-flow gasifiers could process the coals, but these units work best with oxygen firing; thus, for small-scale applications like this one, a premium price for the fuel gas produced must be paid because the price of fuel gas would include the cost of a less-than-optimum-size oxygen plant. The rationale for selecting a fludized-bed gasifier is that it can accept ⅜ in. × 0 coal and can operate on air.

For the industrial-park application, Davy chose low-sulfur coal as a feedstock for the coal-gasification plant so that hydrogen sulfide (H_2S) removal is not required, and the gas can be delivered hot to the end users. Besides being thermally efficient, this mode of operation also precludes the need for wastewater treatment since the produced fuel gas never reaches its dewpoint.

Process description

The coal-gasification plant was sized to process 600 tons/day of Montana subbituminous coal to

Table 1: Coal feedstock[1]

Item	Weight %
Proximate analysis (as received)	
Moisture	16.9
Volatile matter	32.2
Fixed carbon	45.2
Ash	5.7
	100.0
Ultimate analysis	
Hydrogen	5.3
Carbon	78.0
Nitrogen	1.3
Oxygen	14.6
Sulfur	0.8
	100.0
Ash analysis[2]	
Phosphorous pentoxide	0.04
Silicon dioxide	39.02
Iron oxide	10.68
Aluminum oxide	21.58
Titanium oxide	0.53
Calcium oxide	8.02
Magnesium oxide	3.23
Sulfur trioxide	13.61
Potassium oxide	1.23
Sodium oxide	2.06
	100.00
Ash-fusion temperatures, F (oxidizing atmosphere)	
Initial-deformation	2380
Softening	2460
Fluid	2520

[1] Montana subbituminous coal (Mammoth seam); higher heating value is 10,510 Btu/lb (as-received) [2] Normalized analysis, laboratory analysis total of 99.12% by weight

Table 2: Composition of fuel gas leaving battery limits

Component	Volume-%
Carbon monoxide	20.58
Hydrogen	12.06
Methane	0.74
Carbon dioxide	6.64
Nitrogen	52.86
Water vapor	7.01
Hydrogen sulfide	0.09
COS	0.02
	100.00
Average molecular weight, lb/mole	25.15
Higher heating value,[1] Btu/scf	118
Lower heating value,[1] Btu/scf	111

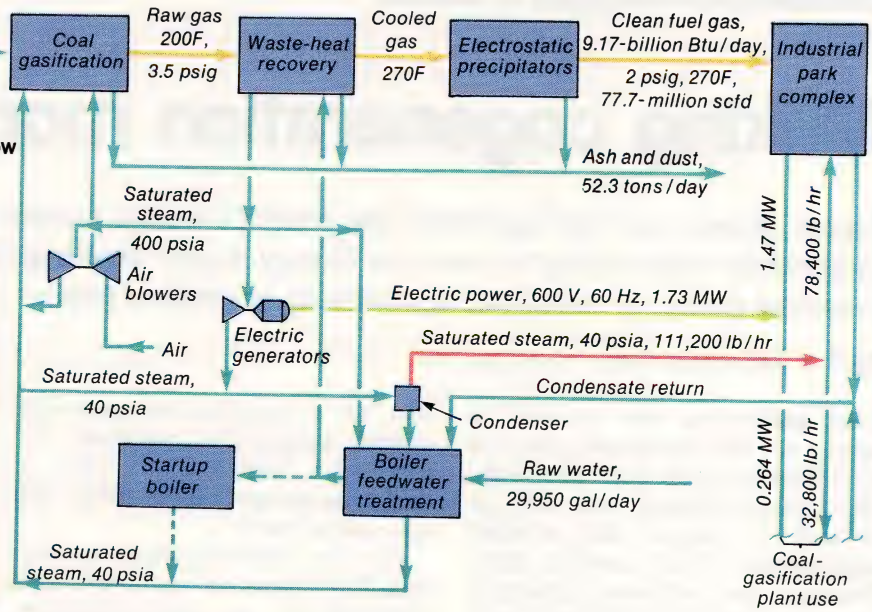
[1] Includes sensible heat of gas above 60F

Table 3: Combustion characteristics[1]

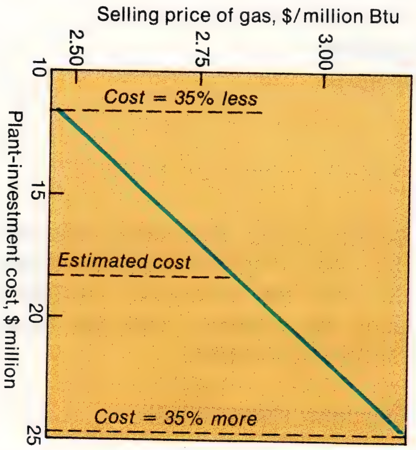
Item	Amount
Adiabatic flame temperature, including dissociation, F	2900
Flue-gas products	
Scf/scf of gas burned	1.69
Scf/million Btu of gas burned	14,320
SO_2 products	
Lb SO_2/million Btu of coal feed	1.1
Lb SO_2/million Btu of gas fired	1.57

[1] Assuming stoichiometric air

1. Coal-gasification plant is sized to produce 9.17-billion Btu of fuel-gas energy, 1.88-million lb of steam, and 35,280 kWh of electric power daily



2. Effect of cost-estimate accuracy, based on $25/ton coal, is shown below



yield 9.17-billion Btu/day of fuel gas energy, 1.88-million lb/day of steam, and 35,280 kWh/day of electric power to the industrial park (Fig 1). The plant is a grassroots facility, assumed to be near an existing railroad. A description of the plant follows:

Coal unloading and preparation. Run-of-mine Montana subbituminous coal (see Table 1) is delivered by rail to the coal-gasification plant. Due to the cold climate, thaw sheds are included. Vibrating feeders on track hoppers feed a conveyor system to deliver coal to a crusher where the coal is crushed to 3/8 in. × 0. From the crusher the coal is conveyed to a 600-ton-capacity coal feed bunker. The unloading and preparation unit is also equipped for stockpiling and reclaiming coal.

Coal gasification. Coal from the feed bunker is fed via a rotary feeder through a coal feed screw into the bottom portion of the 16-ft-diameter gasifier. Air and steam are admitted to the gasifier, and combustion/gasification reactions take place at 2000F within the fluidized bed. Because the coal is reactive and low in ash (roughly 6% by weight), engineers estimate that 95% (by weight) of the carbon in the coal will be gasified.

Ash is removed from the gasifier via a screw to an ash bunker. From the bunker a rotary feeder feeds an enclosed conveyor, which delivers the ash to a storage bunker for removal to landfill by truck.

Hot gas at 2000F leaves the gasifier and flows down through a heat-recovery boiler/boiler feedwater preheater, exiting from the preheater section at 270F. Saturated steam at 400 psia is produced in the heat-recovery boiler. Dust that settles out in the bottom of this boiler is fed via a rotary feeder to the enclosed ash conveyor.

The cooled gas passes through a cyclone collector where more dust is removed. Finally, the gas travels through two electrostatic precipitators for final particulate removal. The particulate loading of the gas exiting from the precipitators is expected to be 0.01 gr/scf or less. The clean 270F gas at 2 psig enters the fuel gas main, and is distributed to industrial-park uses.

Offsites. The 400-psia saturated

Table 4: Overall material and energy balance

Component	Million lb/day	Billion Btu/day	% Energy
Input			
Coal at 10,510 Btu/lb and 60F	1.200	12.612	100.0
Water at 60F	0.250	—	—
Air at 60F	3.937	—	—
	5.387	12.612	100.0
Output			
Gasification plant:			
Steam heating[1]	—	0.448	3.6
Heat loss to atmosphere[2]	—	0.447	3.5
Electricity	—	0.021	0.2
Blowdown/deaerator	0.130	0.104	0.8
Ash/char	0.105	0.543	4.3
	0.235	1.563	12.4
Industrial park:			
Fuel gas	5.152	9.172	72.7
Steam[1]	—	1.757	13.9
Electricity	—	0.120	1.0
	5.152	11.049	87.6
	5.387	12.612	100.0

[1] Average steam rates based on total annual rates with five months of winter operation [2] Includes all estimated heat losses from the steam heating systems for the gasification plant and industrial park. Condensate return assumed at 200F

Table 5: Projected operating costs for coal-gasification plant[1]

	Annual use	Cost/unit	$1000/yr	Gas cost, $/million Btu
Raw material				
Coal	198,000 tons	$25/ton	4950	1.64
Chemicals				
Water treatment	9.9-million gal	$0.15/1000 gal	1	— —
Utilities				
Clean raw water	60-million gal	$0.20/1000 gal	12	— —
Electricity	2.06-million kWh	$0.03/kWh	62	0.02
Steam	260-million lb	$2.50/1000 lb	650	0.21
Labor				
Process operating	36,000 hr	$9.00/hr	324	0.11
Maintenance	— —	— —	349	0.12
Supervision	— —	— —	135	0.04
Administration and general overhead	— —	— —	485	0.16
Supplies				
Operating	— —	— —	97	0.03
Maintenance	— —	— —	233	0.08
Local taxes and insurance	— —	— —	491	0.16
		Total gross operating costs:	7789	2.57
Credit				
Electricity	13.7-million kWh	$0.03/kWh	411	
Steam	880-million lb	$2.50/1000 lb	2200	0.73
			2611	0.86
Net operating cost			5178	1.71

[1] 600-ton/day Winkler unit, 3.027×10^{12} Btu/yr, 330 on-stream days/yr, costs assume third-quarter 1978 dollars

Table 6: Capital requirement for coal-gasification plant

Cost component	$ million[1]
Coal unloading, handling, preparation	3.0
Coal gasification, gas cleanup	10.4
Offsites	2.4
Contingency at 15%	2.4
Total investment	18.2
Allowance for funds during construction	4.9
Startup costs[2]	1.6
Working capital[2]	2.2
Total capital requirement	26.9

[1] Assumes third-quarter 1978 dollars [2] Basis: $25/ton coal

steam produced while cooling the fuel gas is used to power single-stage turbines to compress air for gasification, to pump boiler feedwater, and to generate electric power. The exhaust steam from the turbines at 25 psig (saturated) is used as a gasifying medium, steam heating for the coal gasification plant, and for service in the industrial park.

The electric power generated is used in the gasification plant for motors, precipitators, thaw-shed heating during winter operation, and lighting. The balance of the electric power is distributed to the industrial park. Offsites include a boiler-feed-water-treatment unit, a small startup boiler, instrument and plant air units complete with driers, and backup electric power for critical service.

Products and byproducts

Fuel gas. The main product of the coal-gasification plant is fuel gas (Table 2). The plant yields 77.7-million scf/day (9.17-billion Btu/day) of fuel gas energy at a battery limit discharge condition of 2 psig and 270F. Higher and lower heating values for the fuel gas are shown in Table 2. Gasification produces no tar or wastewater.

With stoichiometric combustion of the gas, an adiabatic flame temperature of 2900F, including dissociation, may be reached. The SO_2 liberated is equivalent to 1.1 lb SO_2/million Btu of coal feed or less, which is below the 1.2 value set forth in the 1975 EPA guidelines for coal-fired boilers (Table 3).

Power and steam. Electric power is generated via single-stage steam-turbine/generators to deliver 1.73 MW, 1.47 MW of which are available to the industrial park.

Exhaust steam from the single-stage turbines enters a 25-psig pipeline for distribution. Steam at 111,200 lb/hr and 25 psig (saturated) is produced, with 78,400 lb/hr being available for the industrial park; the rest is used in the gasification plant.

Material/energy balance

Table 4 shows an overall material and energy balance for the coal-gasification plant. The energy balance shows that 87.6% of the coal energy input is available as usable heat in the industrial park. The energy in fuel gas compared to coal input is 72.7%, steam is 13.9%, electric power 1%.

Operating costs were developed assuming 330 on-stream days/yr. Table 5 shows the projected operating costs for the coal-gasification plant. Total gross operating costs were projected from which credits for electric power and steam were deducted, giving a net operating cost of $5.178-million/yr, or $1.71 million Btu of gas produced.

A plant-investment cost of $18.2-million was estimated for the facility. After adding allowances for funds during construction, startup costs, and working capital, a total capital requirement of $26.9-million was estimated (Table 6).

A utility finance method to yield 15% return on equity was used to develop the economic analyses. These assumptions were made: (1) 20-year project life; (2) 20-year straight-line depreciation; (3) debt/equity ratio of 75/25; 10% interest on debt; and (5) federal income-tax rate of 48%.

Making no allowance for inflation, to yield a 15% return on equity (based on 1978 dollars) would require a gas selling price of $2.82/million Btu. If coal could be purchased for $20/ton, the cost would drop to $2.46/million Btu; at $30/ton, the cost of gas would be $3.17/million Btu.

Fig 2 illustrates the effect of cost-estimate accuracy, based on a $25/ton coal feedstock. A variation of capital cost accuracy of ±35% results in a corresponding variation in gas cost of $0.36/million Btu. ■

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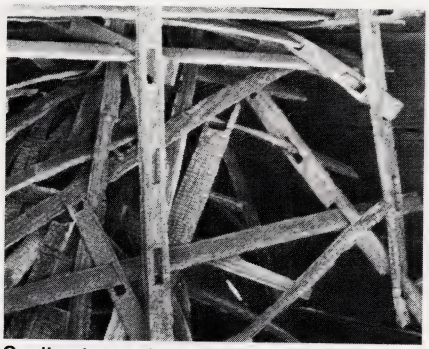

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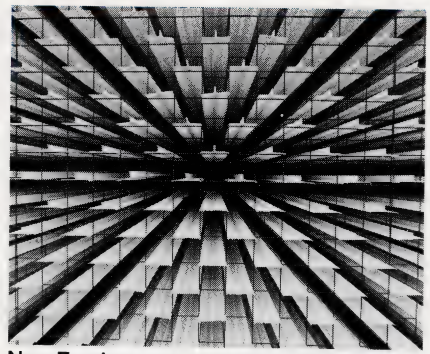

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1	19	37	55	73	91	109	127	145	163	181	199	217	235	253	271	289	307	325	343	361	379	397	415	433	601	619
2	20	38	56	74	92	110	128	146	164	182	200	218	236	254	272	290	308	326	344	362	380	398	416	434	602	620
3	21	39	57	75	93	111	129	147	165	183	201	219	237	255	273	291	309	327	345	363	381	399	417	435	603	621
4	22	40	58	76	94	112	130	148	166	184	202	220	238	256	274	292	310	328	346	364	382	400	418	436	604	622
5	23	41	59	77	95	113	131	149	167	185	203	221	239	257	275	293	311	329	347	365	383	401	419	437	605	623
6	24	42	60	78	96	114	132	150	168	186	204	222	240	258	276	294	312	330	348	366	384	402	420	438	606	624
7	25	43	61	79	97	115	133	151	169	187	205	223	241	259	277	295	313	331	349	367	385	403	421	439	607	625
8	26	44	62	80	98	116	134	152	170	188	206	224	242	260	278	296	314	332	350	368	386	404	422	440	608	626
9	27	45	63	81	99	117	135	153	171	189	207	225	243	261	279	297	315	333	351	369	387	405	423	441	609	627
10	28	46	64	82	100	118	136	154	172	190	208	226	244	262	280	298	316	334	352	370	388	406	424	442	610	628
11	29	47	65	83	101	119	137	155	173	191	209	227	245	263	281	299	317	335	353	371	389	407	425	443	611	629
12	30	48	66	84	102	120	138	156	174	192	210	228	246	264	282	300	318	336	354	372	390	408	426	444	612	630
13	31	49	67	85	103	121	139	157	175	193	211	229	247	265	283	301	319	337	355	373	391	409	427	445	613	631
14	32	50	68	86	104	122	140	158	176	194	212	230	248	266	284	302	320	338	356	374	392	410	428	446	614	632
15	33	51	69	87	105	123	141	159	177	195	213	231	249	267	285	303	321	339	357	375	393	411	429	447	615	633
16	34	52	70	88	106	124	142	160	178	196	214	232	250	268	286	304	322	340	358	376	394	412	430	448	616	634
17	35	53	71	89	107	125	143	161	179	197	215	233	251	269	287	305	323	341	359	377	395	413	431	449	617	635
18	36	54	72	90	108	126	144	162	180	198	216	234	252	270	288	306	324	342	360	378	396	414	432	450	618	636

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Comparing PC and stoker firing

In industrial boilers, especially smaller units, pulverized-coal firing is becoming increasingly attractive as coal prices soar. Here's how to make the economic evaluation

By D C Williams, Babcock & Wilcox Co, Industrial & Marine Div

With the increasing shift to coal, industrial boiler operators are finding that they face a difficult economic choice between pulverized-coal and spreader-stoker firing for new boiler applications.

In the past, most coal-fired boilers below 300,000-lb/hr steam capacity were stoker-fired, while larger boilers almost always used pulverized coal. As the price of coal continues to rise, however, pulverized-coal-fired (PC) boilers with steam capacities as low as 100,000 lb/hr are often economically attractive.

New boilers with low steam capacities can be designed to burn coal efficiently by either method. With the required steam conditions and flow in mind, each decision normally is based on a careful evaluation of seven factors: capital cost, fuel cost, efficiency, auxiliary power cost, pollution control, maintenance, and operation.

Capital cost. A PC unit generally costs more than a spreader-stoker unit of the same capacity. The controlling price factors usually include type of coal, steam conditions, and pulverizer requirements. The right application, however, often justifies the higher initial expense.

An industrial plants, steam flow, temperature, and pressure requirements are almost always determined by factors outside the boiler island. They are considered first in designing a unit, and they directly affect the capital cost of boilers, regardless of firing method.

Another important capital-cost factor is the coal to be burned. Furnace volume can vary by as much as 30% in a PC unit, depending on the slagging potential of the coal. Severe-slagging coals require very large furnaces in PC units. Stoker furnace size, on the other hand, is affected less dramatically by slagging—although performance can be greatly hindered by caking coals, and furnace size will vary with higher-slagging coals.

In short, the type of coal to be burned has a major impact on unit cost. Obtaining long-term coal contracts is usually difficult for industrial buyers, so it's very important in a cost evaluation to determine and specify the *worst* coal that might be burned. Evaluation on a worst-coal basis will more closely reflect the reality of sizing and operating the boiler over its expected life.

Fuel cost. After the design coals have been identified, specific fuel requirements of PC and stoker firing must be examined. In particular, coal size can have a significant impact on ultimate fuel costs. Both PC and stoker firing require coal sized no larger than 1¼ in. PC firing has no minimum size requirement; stoker firing, however, has practical limits to the amount of fine particles that can be injected into the grate.

Specifically, for traveling-grate spreader stokers, it is recommended that no more than 40% of the coal pass through a ½-in. screen, and no more than 7% through a 40-mesh screen. Going beyond these limits will compromise unit efficiency. Too many fines also result in high carryover to the dust collector; on the other hand, too little large coal can lead to poor coal distribution on the stoker and high unburned-combustible loss. Recommended coal sizes for other types of stoker-firing systems are shown graphically in the POWER special report reprint, *Power from coal.*

The minimum-coal-size requirement often means that the boiler owner has to pay a premium for properly-sized coal. Mines that are not equipped to provide coal to stoker specifications may charge $5 to $10 more per ton for double-screening. Some industrial-boiler operations, therefore, maintain crushing and screening facilities at their own plants, to assure proper sizing. If the coal has too many fines when it is delivered, however, no amount of crushing and screening can provide the coal sizing needed for efficient burning.

Assuming that an industrial boiler user has to pay $40/ton for unsized coal for a PC unit and $45/ton for properly-sized coal for a stoker, then this 12.5% premium may often tip the economic evaluation in favor of pulverized coal when boiler load-capacity factors are high.

Boiler efficiency directly affects fuel costs, too. PC firing has an advantage here because of the comparatively high amount of unburned-combustible loss that occurs during stoker firing. A stoker burning a midwestern bituminous coal with 30% volatility may have an unburned-combustible loss of roughly 6% with no flyash reinjection, 4.5% with reinjection from boiler and economizer hoppers, and 2.8% with reinjection from the boiler, economizer, and mechanical-dust-collector hoppers.

A PC boiler of the same capacity and burning the same coal will have an unburned-combustible loss of only about 0.8%. Based on this comparison, the pulverizer unit will use between 2% and 5% less fuel than the stoker-fired boiler at normal continuous steam flow.

The unburned-combustible loss from a stoker-fired boiler decreases with steam load, whereas the loss from a PC-fired unit remains almost constant. At half load, the PC unit would still use between 1% and 3% less fuel. These savings, of course, become more significant as coal prices rise.

Auxiliary-power cost. Economic evaluation of firing methods is also affected by the amount of power required for auxiliaries. Based on steam capacity, it is easy to calculate fan capacities and the operating horsepower required for motor drives. The other major power consumers are fuel-related—the stoker and the pulverizers.

Pulverizer power requirements vary inversely to the coal's grindability and heating value. Depending on the coal burned, a PC unit would require from 40% to 60% more horsepower over its entire steam-capacity range than a

spreader-stoker unit. A typical 200,000-lb/hr boiler burning bituminous coal, for example, would require approximately 900 hp if it were PC-fired. A spreader-stoker with equivalent steam flow would require roughly 650 hp. An electrostatic precipitator for either application would require approximately 200 kVA.

Air-pollution control. Both PC and spreader-stoker units require extensive air-pollution-control equipment. Because coal-fired boilers cannot be designed to limit sulfur emissions, industrial users are left with two alternatives: low-sulfur coal or flue-gas-desulfurization systems.

A 200,000-lb/hr boiler with either firing method would require a capital investment of several million dollars for a sulfur-removal system, assuming coal with 4-5% sulfur content. Also, a sulfur-removal system is expensive to operate and maintain. These costs are offset somewhat by the lower purchase price of high-sulfur coal.

A greater pollution problem with PC units are nitrogen oxides (NO_x), mainly because of the higher flame temperatures in PC firing. The stoker's combustion process takes place at temperature levels such that the NO_x generated is within today's federal EPA limits.

NO_x emissions from PC boilers can be controlled with special designs. Modern industrial PC units cool the burner flame rapidly, while at the same time limiting the amount of combustion air available at areas of high flame temperature. Low fuel input per burner and widely spaced burners reduce peak flame temperature quickly.

Another contribution to NO_x control is to keep excess combustion air at a minimum—via compartmented windboxes, for example, which supply air individually to the group of burners fed by each pulverizer, with excess air being introduced above the burners. Research continues on the development of means of lowering NO_x emissions still further.

Because PC units burn coal in suspension, they also need a higher efficiency of particulate removal than do small stoker-fired boilers. To meet federal and state regulations, industrial boilers require electrostatic precipitators with very high efficiencies. Some units use baghouses or other control devices.

Stoker-fired boilers also require some kind of particulate removal. For larger units, this normally includes mechanical dust collectors as well as precipitators or fabric filters. In some states, where particulate-emission standards are less stringent for boilers with less than 250-million Btu/hr of heat input, a two-stage mechanical removal system may be sufficient. On new units, however, ductwork should be designed so a precipitator can be added in the event of stricter controls in the future.

Comparison of pulverized-coal-fired and spreader-stoker boilers

Item	Spreader stoker	PC
DESIGN PARAMETERS		
Capacity, lb/hr	210,000	210,000
Pressure, psig	160	160
Steam temp, F	Saturated	Saturated
Heat input, million Btu/hr	247	244
Particulate-emission limit, lb per million Btu/hr	0.4	0.4
POWER COST		
Total horsepower	522	806
Total kW[1]	389.4	601.3
$/kW	0.041	0.04
Power cost, $/8800 hr	140,500	216,900
Difference, $	−71,100	
MAINTENANCE COST		
Cost per ton of coal burned, $	0.05	0.10
Cost, $/8800 hr	5192	9724
Difference, $	−4532	
FUEL COST		
Efficiency, %	79.9	85.6
Heat input, million Btu/hr	259.6	243
Fuel consumption, tons/hr[2]	11.8	11.05
Fuel cost, $/ton	45	40
Fuel cost, $/8800 hr	4,672,800	3,889,600
Difference, $	−783,200	
ECONOMIC EVALUATION[3]		
Base price, $	Base	+500,000
Cost of money, $	−50,000	
Power cost, $	−71,100	
Fuel cost, $	+783,200	
Maintenance cost, $	−4532	
Total	657,500	500,000

[1]Not including precipitator [2]Assumes 11,000-Btu/lb coal [3]Assumes operation at full load for one year

Before selecting a particulate-removal system for either firing method, a detailed coal analysis should be made. For PC units, flyash characteristics also must be determined; for stoker-fired units, stoker design and flyash reinjection also must be considered.

Maintenance. While comparative data on maintenance costs for PC and stoker firing are not readily available, experience shows that the costs for bituminous-coal-fired boilers would be about the same for both. On coals with low heating value, low grindability, or high-sulfur content, maintenance costs will be higher for PC units than for stoker-fired units of comparable size.

Maintenance of pulverizers can be performed while the boiler is in operation. On the other hand, the boiler must be shut down and cooled before major stoker maintenance can proceed. Such lost production may outweigh the extra maintenance cost for pulverizers.

Operations. At some plants, operating practice may override economic considerations in choosing between PC and stoker firing. Low load factors, for example, may favor the economics of stoker firing. PC units are generally more flexible in their response to load changes, and they can operate at low loads without the smoking problems encountered in spreader-stoker firing.

For optimum performance, spreader-stoker operators must be highly experienced in maintaining proper furnace conditions for efficiency and emissions control. In addition, automated controls—including burner monitors that automatically trip the boiler in case of abnormal flame conditions—make operating PC units both safe and efficient.

A comparative example. The table shows a simplified example of how the various factors come into play in an economic evaluation between stoker and pulverizer firing. Keep in mind that this simplified case makes no provision for taxes or depreciation, and the cost of capital is only approximated.

It reveals that a stoker-fired boiler of 210,000-lb/hr capacity has a purchase price that's $500,000 less than a PC unit with the same steam flow (say $3.6-million vs $4.1-million). Because of the lower price, financing is also less expensive for the stoker-fired unit. Assume roughly $50,000 additional interest charges for the PC unit.

The table shows that, in this case, stoker firing also has the advantage in terms of the costs of auxiliary power and maintenance. Recall that mills account for the higher horsepower requirement of the PC unit.

The evaluation of fuel requirements and costs, however, tips the economic balance in favor of pulverized coal. The combination of higher efficiency and the premium paid for stoker-sized coal make a difference of more than $700,000 in fuel costs over one year of operation at full load. Last section of the table shows how this cost has the ultimate result of making PC firing the economical choice for this plant.

PC firing, of course, may not be the more economical for every installation. Depending on the application, the margin of efficiency in favor of PC firing can range from 2% to 7%. Coal prices can vary from $20/ton to $45/ton, and the premium on double-screened coal for stoker firing can range from zero to as high as $10/ton. The capital-cost difference will also vary greatly with fuel requirements and steam capacity. ■

Applying digital computers for monitoring and control

Digital computers are sophisticated devices that have not been used fully or wisely in some control systems. Here's how industry can apply them to save energy, cut costs, and reduce maintenance

By Dian P Jen, International Business Machines Corp

Computers are performing various monitoring and control functions that lead to significant energy savings and operating cost reductions. In most cases, however, these functions are limited, unsophisticated, and do not take advantage of the computer's full capability. The real challenge today is determining the best trade-off between computer software/hardware, front-end monitoring, and control hardware. The result can be a substantial reduction in initial capital investment and subsequent maintenance costs.

This article examines some of the generic and specific functional capabilities of digital computers that contribute to applications related to energy management.

Generic functions

Generic functions relate independently to specific applications. They provide the basic intelligence of a digital-computer-based system. The four key system elements are operations monitoring, analysis functions, management information, and operations control.

Operations monitoring involves functions designed to ensure systems reliability, maintain data integrity, and provide maximum visibility of facilities operations. It covers the areas of data acquisition and analysis, digital filtering, engineering conversion, and information storage.

Basic functions performed by the operations monitor include scanning of status points and analog measurements, straight conversion of engineering values, limit checks, and alarm and data storage. These functions don't contribute directly to energy savings, but unless a high performance level is maintained the information may be of little or no significance.

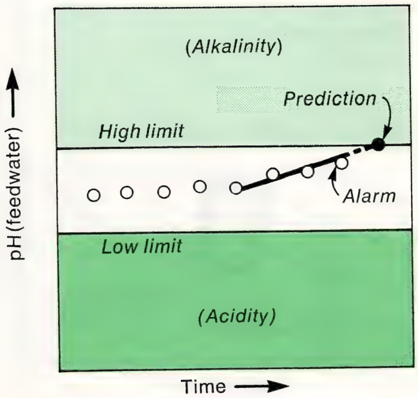
The high-speed arithmetic capabilities of the computer can be capitalized on to improve system performance substantially. Digital inputs, for example, can be analyzed for a summary of status changes, cumulative equipment run time, and outstanding maintenance alarm. The data in turn can be used to generate equipment usage reports and preventive maintenance work orders. As a result of this and other improvements, facilities operations and maintenance personnel have total visibility of individual equipment or systems-performance information in either tabulated or graphic form.

Analysis functions. The operations monitor can only provide a reliable, accurate, and complete status-information system. When the monitor is used as the basis for an advanced analysis program, system effectiveness is multiplied. Standard analysis programs include:

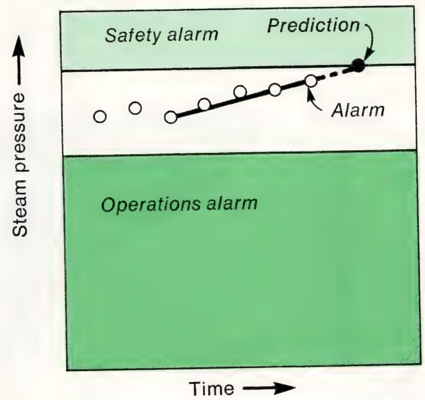
- Trend analysis and predictive control. A basic function using linear programming or polynomial curve-fitting techniques. Its product is a mathematical equation that represents the trend of a process variable based on a fixed number of past and current measurements (or calculated values).

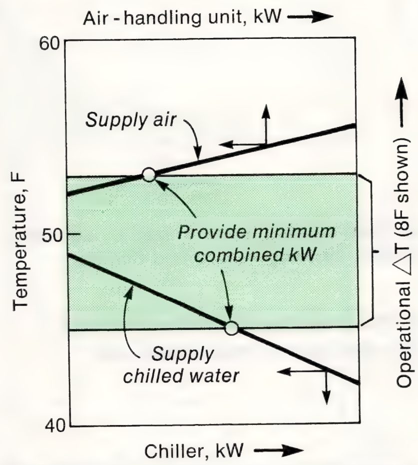
The program can automatically analyze and answer such questions as: Is the cooling load increasing? Is the space temperature moving toward the high limit? Is boiler efficiency deteriorating? Is steam pressure approaching its critical limit? Fig 1 illustrates how two of the major variables of boiler operations can be monitored for preventive-maintenance analysis. The predicted values could be used as input for an application program or to generate a maintenance message. If required, it could trigger an audible alarm.

- Regression analysis. An on-line regression-analysis program is one of the most powerful tools offered by digital computers. A mathematical equation is generated to identify the interrelationship of a number of selected process



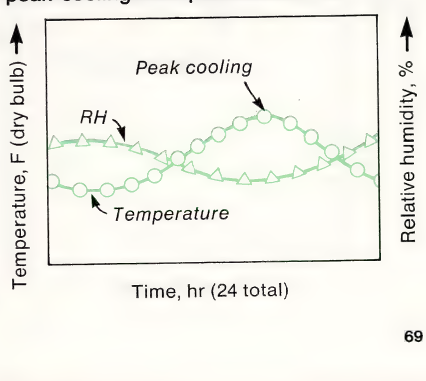
1. Preventive maintenance is monitored for two key boiler variables (above, below)

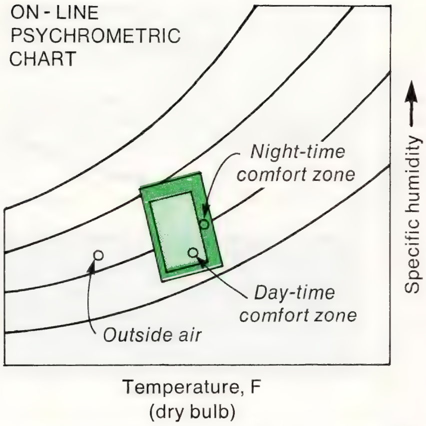




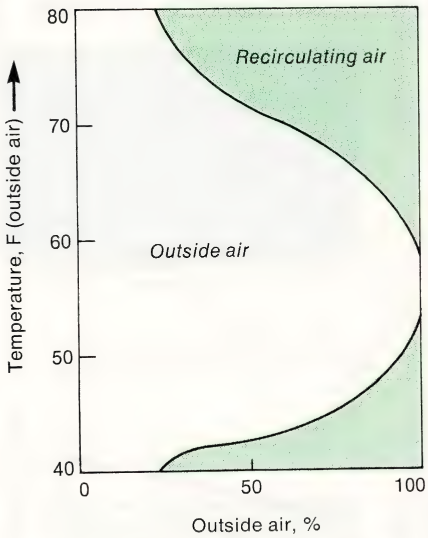
2. Trade-off of chilled-water temperature and supply-air temperature is for a variable-volume air-handling unit

3. Weather analysis is used here for peak-cooling-load prediction



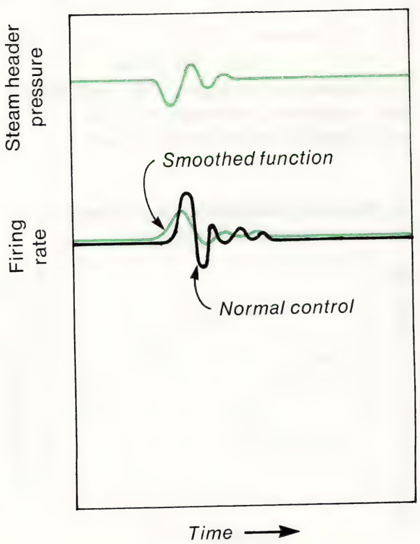


4. Psychrometric analysis can determine minimum energy consumption to maintain space conditions within specific limits



5. Free cooling is maximized by adjusting supply-air temperature and dampers

6. Time response of control function smooths out the boiler firing rate



variables. A program with two to five parameters and a single dependent variable can determine very quickly, for example, whether the steam consumption is more closely related to weather conditions, equipment usage, or the number of people in the building.

The same function could be used in reverse to determine steam-generation and boiler-capacity scheduling based on the changes (or anticipated changes) of those three parameters. The boiler excess combustion air, as another example, can be controlled as a function of the boiler firing rate, higher heating value of the fuel, and furnace draft.

■ Performance trade-off analysis. Accurate equipment performance, important for maintenance, is difficult to obtain manually. Boiler efficiency and chiller performance factors, for instance, vary according to load conditions. Equipment efficiencies commonly are calculated either manually over a period of time, or automatically by an on-line digital computer. When used for on-line equipment selection and scheduling, this information becomes considerably more effective.

By correlating operating efficiencies with various load conditions, the digital computer can be programmed to select equipment that will perform at near peak efficiencies under anticipated load conditions, possibly leading to a reduction in equipment overhead, operating time, and energy consumed by utility throughput. An example is the trade-off between the control of supply air temperature vs supply chilled-water temperature for a large variable-volume air-handling system. When treated separately, the most economic operation can be obtained when the supply air temperature is at its minimum and the chilled-water temperature at its maximum.

But these objectives aren't always compatible because the chilled-water temperature may be so high that the reduction of the supply air temperature can no longer be obtained. It may be beneficial to reduce the chilled-water temperature. However, since the cost of each operation is dependent on variables like load level, on-line equipment capacities, and equipment performance level, it can only be handled by an on-line economic analysis program (Fig 2).

■ Weather analysis. Weather is always a variable that represents a significant load in heating, cooling, and humidity control. Therefore, weather conditions should be analyzed and predicted to schedule loads, thereby minimizing excess capacities.

Real-time weather analysis and prediction can be done with a rooftop weather station and digital computer. A weather model based on empirical and statistical principles can be updated continuously by station data. As a result, dry-bulb temperatures and humidities at selected time intervals during a 24-hr period can be predicted with excellent results (Fig 3).

■ On-line psychrometric analysis is one of the most effective energy-saving techniques for controlling space conditions. Not only does the analysis provide total visibility of space conditions, but it also identifies a two-dimensional space condition range, which is necessary for maintaining minimum energy consumption (Fig 4).

Dimension specifications consist of four pairs of coordinates that define specific humidity and dry-bulb temperature. They should be on-line modifiable to permit unlimited flexibility in specifying space condition requirements. The arrangement also enables the computer to calculate control setpoints to maintain space conditions precisely.

Management information. An information system should provide useful data for generating on-line control functions and formats for man-machine communications. On-line digital computers can produce reports, for example, on maintenance, equipment usage, energy consumption, maintenance work orders, and repair parts inventory.

Operations control. A digital computer is commonly used for basic process control. But to fully utilize the capabilities of the device, complex functions should be incorporated into the program to provide optimized control of process variables under all load conditions.

In the case of boiler optimization, the following control functions should be considered to complement supervisory or direct-digital control:

■ Firing rate = f (steam pressure at the header, steam pressure downstream, steam flow, boiler efficiency, furnace-wall temperature gradient).

■ Feedwater rate = f (level in water drum, steam header pressure, steam flow).

■ Excess air = f (firing rate, draft, higher heating value of fuel, fuel analysis).

All parameters in these functions can also be generated by either another time-dependent function or on-line manual input.

As a typical example, the boiler firing rate could be controlled to provide a different response function when under normal operation, a cold start, or an exceptionally large step change. This function requires design experiment, but once it's established, control is automatic, and the best transfer function is provided for each controlled variable.

Specific applications

A multitude of special computerized techniques can be applied to obtain

maximum performance and energy efficient operations, as the following shows.

Air-handling systems. Free cooling is one of the most significant energy-saving techniques. By adjusting the mixing air-temperature setpoint and the supply air temperature leaving the coil, the actual free cooling range can be increased (Fig 5). The computer identifies the most economical operating point on the on-line psychrometric diagram and adjusts the supply air temperature and damper opening to achieve maximum free cooling. It also can lead to delayed chiller start-up, achieving further energy savings.

Under computer control, the power to drive a variable-volume air-handling system can be reduced by delivering less air with dynamic adjustment of the supply air temperature. By lowering it for cooling and raising it for heating, air volume and its associated fan-motor horsepower requirements can be substantially reduced. For constant-volume air-handling systems, however, the supply air temperature should be maintained at the highest possible level for cooling and the lowest possible level for heating.

Chilled-water systems. In general, chiller operating efficiency is directly proportional to the temperature difference between supply chilled water and entering condenser water. To maintain the highest level of chiller performance, the supply chilled-water temperature should be maintained at the maximum allowable level, while condenser water temperature should be at the lowest allowable level. With all types of chillers, energy savings could result from reduced electricity or steam usage (that is, a narrower temperature difference).

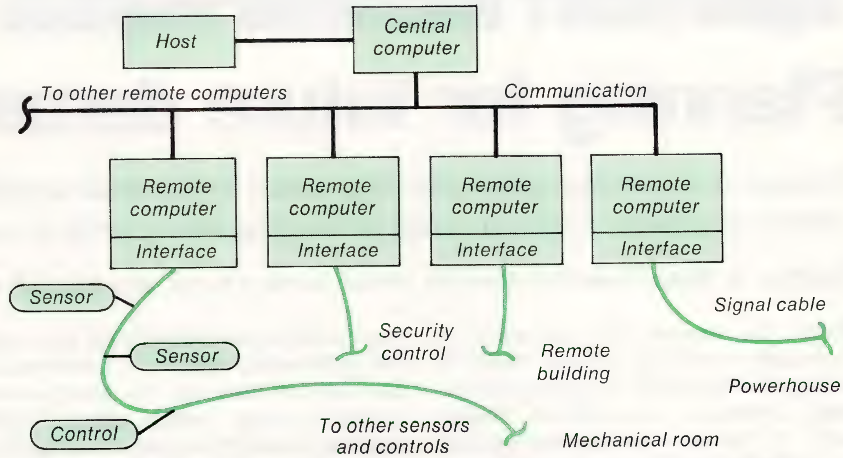
Dynamic adjustment of the chilled-water supply temperature should be a function of the chilled-water return temperature, chilled-water flow, the actual cooling load and its trend, and space-conditioning requirements. Entering condenser water temperature should be controlled as a function of the cooling tower thermal load and outside wet-bulb temperature.

A key advantage of a digital computer vs a conventional control system is that the computer system can be programmed with control functions using measured and calculated variables, thereby optimizing chilled-water system operation.

Steam/hot-water regulation includes boiler operation, in which digital computers generally have been used only for fundamental monitoring functions because of the heavy investment required for instruments. However, simple controls for excess air and furnace draft can be applied effectively with a digital computer.

The use of these devices in the steam/hot-water generation and distribution area requires additional high-quality instruments to measure flow and pressure at strategically selected points for achieving complete flow balance on a realtime basis. Control valves with modulating capability are also necessary to minimize waste in flow distribution at all pressure levels.

Besides showing how much and where steam or hot water is used, the on-line flow balance also helps detect line problems such as leakage or defective steam traps. A sudden drop in pressure, due to an unexpected change in steam usage at the consumption point, is detected by sensors that signal the computer before the pressure drop is felt by the firing rate control hardware. Depending on the size of the drop, the computer automatically selects the proper control function for a smooth change in boiler firing rate (Fig 6). Thus, the boiler is operated with less fluctuation, raising its average efficiency and reducing energy consumption and maintenance costs.



7. Distributed system with a central processor interfaces with remote computers

Distributed intelligence

Distributed systems, already well known in the data-processing industry, may become a future trend in facilities and energy management. Small digital computers can be programmed to perform certain fixed or simple functions at distributed or remote locations.

A host computer improves central analytical capability and provides an interactive interface for the complete network. It receives, stores, and analyzes information from remote processors and then makes logical or analytical decisions. Commands are sent to remote processors for execution (Fig 7).

With computers becoming more efficient and less expensive, industry can use more but smaller computers to form a distributed monitoring, control, and communications network. Advantages to selecting a distributed system:

- Dependency on the central system is reduced because remote processors are self-sufficient in performing reduced and noninteractive functions.
- For the total system, hardware and software costs are less per function on a per-point basis. One central computer provides the required intelligence. Software for the remote computer is simple and transferable.
- The capacity for total monitoring and control points that can be handled by one central processor is increased significantly.
- Hardware and software provide easy, inexpensive, and almost unlimited expansion.

One of the few disadvantages is the initial investment, which is becoming less as the price of computers declines. Also, users must undergo a learning experience in installing and working with a distributed energy-management system.

A screen-driven English language technique allows the user to generate his own system. He can format his own reports, structure his own control strategies, and make changes without interrupting the entire system. Also, a high-level language should be provided so other applications programs for nonenergy functions can be easily written and linked to the on-line scheduler. Only such a system can make the user totally self-sufficient and fully satisfy the requirements of his facility.

The outlook

A computer can greatly assist industry in cutting energy consumption. Within a matter of seconds, it can process a large amount of data, perform a multitude of complex mathematical operations and logic analysis, formalize vast numbers of diversified commands, and execute various control functions ranging from the very simple to the very complex.

As more sophisticated computer techniques are developed and cost performance is improved even more, on-line digital computers will become part of the standard equipment used in industry. ■

Planning for future demand

Though not a critical early-planning factor in the past, availability of adequate electric power is a major concern today in locating new plants or planning major expansions

By Blair A Ross, American Electric Power Service Corp, and **Ronald A Smith,** General Motors Corp

While the demand for electricity is constantly increasing, utilities' ability to satisfy that demand is becoming increasingly uncertain and difficult. Rising costs of fuel and construction, sparked by inflation and environmental standards, have made the cost of providing new generating capacity especially expensive. And not only have costs increased disproportionately, but the time required to construct additional capacity has lengthened considerably. These factors make it imperative for utilities and industry to develop and maintain a policy of mutual planning and cooperation, not only for plant construction and projects, but for the entire life of the producer/consumer relationship.

Integrated planning between the utility and industry is vital at all phases of industrial-plant development. Industrial demands for power, in many cases, call for new substations. The construction of these facilities involves detailed planning and engineering studies. To accommodate demand increases, the utility must evaluate existing system capacity and appraise its ability to serve anticipated demand increases. Further, the utility and the industrial customer need to resolve many questions with respect to rates, method of service, and service contractual arrangements, many of which may require regulatory approval.

As a general rule, performing the various functions required to place new facilities in service requires as long as 24 months. In exceptional cases, where right-of-way or regulatory permission is disputed, a longer time may be required. Recognizing this, utilities and industrial customers must endeavor to evaluate new service requirements and begin planning work on facilities at the earliest possible date.

Many of the planning aspects pertaining to supply facilities and capacities apply to other utility supplies as well. And while there may be differences between electrical-supply needs and water, natural gas, and sewage, many concepts are the same—though there may be added problems of supply, curtailment, and pricing associated with gas.

Utility capacity requirements. Today the typical electric power system is faced with severe constraints in its ability to increase central-station capacity rapidly. Based on current experience, coal-fired generating plants take 5-8 years from siting to construction, and nuclear plants 10-12 years. Thus, most of the fossil generation and all of the nuclear generation for the 1980s must already be at least in the siting stage. In the light of this constraint, it is possible that, in some areas of the country, industrial plant expansion or new plants may present demands that will be difficult to accommodate.

General Motor's integrated approach to

Recent facilities-expansion activities, coupled with compressed timing and increasing supply uncertainties, have led General Motors Corp to develop an integrated approach to electric-utility supply planning, including conducting utility-supply evaluations for new plant sites and for handling major plant expansions. There are six basic steps in this approach:

Assist divisions with corporate administrative procedures used for new-site evaluations and facilities expansion.

Develop utility-supply service and facility requirements incorporating immediate, five-year, and long-range load and usage projections, taking into account potential impact due to gas/oil conversions, increased production, and new technology. A site-plan layout and a plant one-line supply and distribution information checklist are also helpful. An in-plant power-system modernization analysis may be necessary if a major production increase or plant expansion is planned; if plant firm capacity may be outgrown in 3-5 years; or if 5 years have elapsed since the last power study—even if there have been no dramatic changes in the plant.

Evaluate capability of suppliers to meet requirements for new and/or existing sites by analyzing each supplier's latest annual report, financial situation, bond rating, construction program, transmission-line and switching-station map, standard terms and conditions of service, as well as rates, facilities costs, capacities, transmission service conditions to the site, and provisions for future capacity expansion.

Communicate with suppliers for preliminary evaluations, using a general guideline and checklist. This ensures that a complete analysis is made, and that all potential service problems are uncovered. It also ensures that needed information regarding the utility is obtained.

Negotiate with selected supplier to finalize terms and conditions of service.

Issue a letter of authorization to the supplier, together with execution of any required service agreements.

An extensive set of guidelines and planning checklists have been developed to organize these six steps into a comprehensive process. Time, effort, and cost are thus reduced in making site evaluations, in conducting and finalizing negotiations, and in providing facilities-planning assistance for existing plants.

Load and facilities planning aspects are defined separately for the utility and for the plant, using a specific facilities-planning guideline. By comparison, future triggering points can be identified, denoting the timing at which specific actions should be taken by the plant and supplier to improve supply facilities and/or services. Marginal service conditions for existing plants are also identified, thus avoiding possible future supply constraints.

Prior to the first formal discussion with the supplier, GM forwards load materialization data, a proposed one-line diagram, information required from the supplier, sample letter of authorization, GM's standards for electric service, a facilities layout plan, and the right-of-license agreement. The supplier then marks up the letter of authorization and the right-of-license agreement to meet its requirements, and prepares draft construction and firm power contracts, a one-line of the service-supply arrangement proposed, and provisions for meeting future capacity expansion. In this manner, both GM and the supplier are able

Utility organization structure. Basic contact with the industrial customer is provided by a utility's customer-service department or representatives, whose importance cannot be over emphasized, for it is through them that specialists within the industrial and the utility organization establish the exchange of information required to coordinate the development of facilities to serve new industrial demands.

After the initial contact, the utility planning department indicates to the customer specific information as to load size and service characteristics that is needed to develop the service plan. The planning department then evaluates the capability of the existing system to serve that new demand. If it determines that the existing system is unable to serve the demand, a program of new facilities to provide the needed capacity most economically is then developed.

The engineering department is then responsible for routing the lines and siting the substations, and for the design of these facilities. At the same time, specific cost estimates are prepared, along with construction requisitions and contractual arrangements.

The utility then determines the costs associated with providing the service, and the adequacy of anticipated revenues to support the necessary investment. The rate department develops rates, tariffs, and service arrangements of the new service.

Finally, the utility's upper-level management reviews all arrangements for serving new industrial demands that involve significant investment in new facilities.

Utility information requirements. To plan for new industrial demands, the utility needs to know the following:

■ Magnitude of new demands. The principal design parameter is the peak anticipated demand, in kilowatts.

■ Load characteristics. The utility requires information as to expected annual energy use, the pattern of energy use anticipated (that is, kWh and load-factor data), facility power factor, and any special characteristics, such as harmonics, voltage dips, and flicker, that may be anticipated from industrial processing equipment.

■ Timing of construction power, test power, and, finally, full operating requirements help coordinate utility service with industrial development.

■ Timing of future increases in the industrial facility's demand beyond the initial requirements may provide substantial savings through proper design and planning of the initial service facilities.

■ Service quality requirements. With respect to frequency of interruption, the effect of voltage dips on process equipment and the effect of system under or overvoltage conditions on process equipment must be considered in developing the service plan. The industrial customer should ascertain whether the economic consequences of possible outages are sufficiently great to justify substantial investments in duplicate substation service facilities, and in automatic circuit-breaker sectionalizing. In many cases, where short-duration interruptions can be tolerated, the substitution of motor-operated air-break switches or manual sectionalizing may be sufficient.

■ System capacity. Manufacturing capacity expansions, either at existing industrial plants or at new plants, are generally based on an assessment of anticipated national and regional economic conditions. Because of this common basis, industrial demand increases tend to have an aggregate effect, with many expansions in an area occurring simultaneously. This aggregate effect may well result in industrial service restrictions because of inadequate capacity if the utilities are not able to provide sufficient system capacity and reserve margins in the future.

Finally, the importance of a coordinated utility and industrial electric service system must be recognized. With the sophisticated computer-controlled processes and automated machinery being installed in many of today's industrial plants, proper coordination of the plant and utility electric systems is vital. To assist customers and utilities, American Electric Power Service Corp and General Motors Corp have developed some conceptual procedures (box). ■

plant-electric utility-supply planning

to quickly review the service conditions and to identify possible areas of disagreement. Moreover, this formalized planning procedure assists GM in short- and long-term strategy, since this planning is made a formal part of our negotiations.

Short- and long-range planning. When GM started working on expanded plant-siting activities two years ago, attention usually centered on some fundamental aspects of the electric utility, such as its construction program, fuel mix, overall financial situation, or current rate costs.

Though these factors are still important, focus has shifted, as a result of assessments and experience, to aspects more directly related to the conditions and terms of service, and the facilities and costs involved in obtaining firm service.

The long-range outlook of many of the suppliers and their ability to obtain adequate capital to support required construction emerged as a major concern. The importance of improving communications with suppliers by building a closer working relationship was also identified as critical.

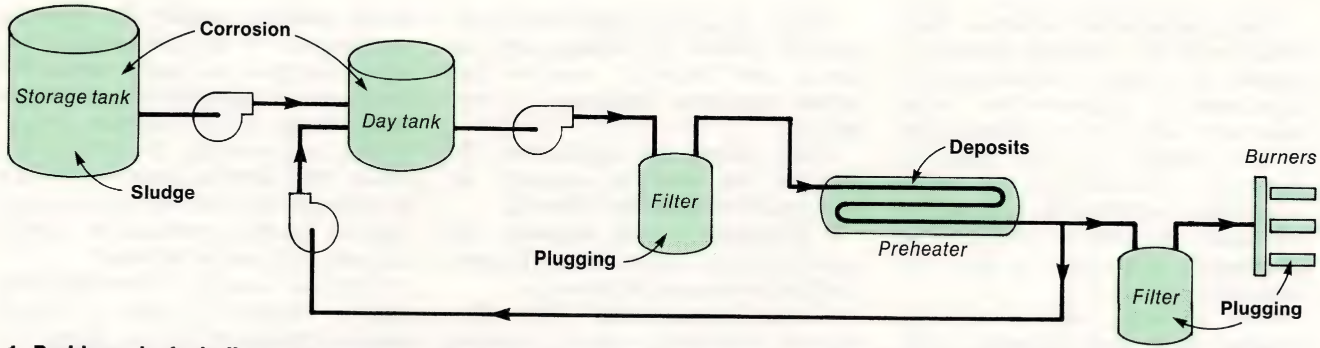
Service-related conditions became even more important. These included capacity available on the suppliers' transmission lines, reliability and adequacy of a high quality of service—especially important if the transmission system is near capacity or is of a lower voltage level—plans for upgrading the transmission system, and previous line-disturbance records of the transmission system serving the site.

Two aspects involving customer/utility coordination and planning must be mentioned. The first is the facilities, space, cost, and timing requirements to increase the primary supply capacity to the next incremental step, either by replacement of the supply transformers with larger units or by addition of a new transformer. The second aspect involves coordination with the supplier's transmission-system capacity planning if any new, significant plant-load increases are envisioned.

Large, unforeseen load increases due to unanticipated plant expansion can present problems if firm transmission or transformation capacity is exceeded. Timing and capacity constraints can then delay availability and reliability of needed power. Typically, substation transformation addition or replacement can require upwards of 16 months, while transmission-system upgrading can require up to two years. New plant requirements, however, can develop within 12-18 months. Being aware of current conditions and being prepared to cope with unexpected load expansions are probably the most crucial parts of the whole planning process.

Expected and potential new load requirements must be carefully coordinated with the supplier's transmission-system planning. System constraints can exist, especially for lower-voltage subtransmission systems in the 40-160-kV range. Typically, utilities upgrade these systems on a planning-cycle basis, such as every five years. New loads, especially if they are a significant part of the supply-system capacity, can be a problem if their timing coincides with the end of the supplier's planning cycle. Being aware of the supplier's position in the transmission-capacity planning cycle ensures coordination for any future load increases.

Initiation of improved facilities supply planning must come from the customer, since the utility's actions and planning depend on the customer's requirements.



1. Problems in fuel-oil storage systems: *Corrosion* of storage tanks from fuel and water containing dissolved corrosive salts; *sludge* buildup in storage tanks from accumulated ash, sediment, corrosion byproducts, and polymerized hydrocarbons; *plugging* in strainers from particles of sludge and rust; and *deposits* in heaters from sludge, coked fuel, gum, and varnish

EQUIPMENT DECISION-MAKING

Use additives to prevent problems

Every stage in the fuel cycle of industrial steam generators—from preflame through emission collection—is a potential problem area. Chemical additives can offer effective solutions when used in a total control program

By J David Martin, Nalco Chemical Co

As energy availability becomes more severe, the use of chemicals as an aid to enhancing fuel utilization becomes increasingly attractive. The fuel cycle, which includes transportation, storage, combustion, heat transfer, and emission collection, has many potential problem areas. The effective use of chemical programs in a total approach to fuel treatment can expedite the handling of fuels and lower the cost of burning them.

After fuels are ready for use, the fuel cycle begins with transportation and storage. Treatment of fuels during this portion of the cycle is known as the *preflame stage.* The benefits of fuel treatment to be gained at this stage are primarily those of lower maintenance and handling cost, increased fuel availability, and longer equipment life.

More complete and, therefore, more efficient combustion can be achieved through the use of combustion catalysts. Copper- or manganese-bearing chemicals have been widely used for this purpose. Magnesium- or manganese-bearing chemicals have been effective for minimizing deposits on heat-transfer surfaces. This chemical treatment results in more efficient heat transfer and in decreased corrosion of metal surfaces.

Chemicals have been used to decrease the emission of undesirable particulate matter. Decreased emissions can mean the difference between (1) continued operation, or (2) financial penalties, or even shutdowns. Chemical treatment may allow increased production rates from a given unit if emissions can be reduced effectively. Realize, also, that improved collection efficiencies of electrostatic precipitators can sometimes provide the capability for burning lower cost fuels, or eliminate the need for building additional gas cleaning equipment such as scrubbers.

Pinpointing the problems

All of the foregoing benefits imply that some very specific problems exist or can exist in the fuel-burning cycle. Because residual fuel oil and coal are commonly the most troublesome fuels, specific problems in their fuel cycles will be detailed here.

Preflame stage. Because residual oil is a mixture of many different hydrocarbons, the propensity for stratification of these different compounds is always present at the oil preflame stage. The heavier hydrocarbons, which exist or may form in storage, can settle in the bottom of tanks and form a sludge that can create these problems:

- Loss of storage volume. Unusable sludge occupies space that would otherwise hold fuel. In times of short supply, this could mean the difference between continued operation and shutdown, or it could force conversion to a more expensive fuel.
- Preflame system fouling. If sludge is transported through the pumps, lines, filters, strainers, heaters, and burners that constitute the preflame system (Fig 1), it can deposit out anywhere in the system, leading to increased pressure drop and decreased flow rate. This could cause poor combustion of the oil if the problem extends all the way to the burners.
- Preflame system corrosion. Oil may contain small amounts of water-bearing corrosive salts such as sodium chloride (NaCl). The corrosive water solution can attack system metal and decrease the life of the equipment.

Traditionally, programs for controlling problems in the oil preflame system have combined active recirculation and temperature control of the oil with the addition of a chemical. The additive will normally be a combination of the following:

- Solvent. Solubilizes a portion of sludge particles already formed in the oil when delivered.
- Dispersant. Coats the sludge particles, which makes them easier to suspend in oil.
- Antioxidants. Minimize the tenden-

Table 1: Melting point of vanadium compounds

Common name	Compound	Melting point, F
Eutectic of $5Na_2O \cdot V_2O_4 \cdot 11V_2O_5$ and $Na_2O \cdot V_2O_5$		990
Gamma sodium vanadyl vanadate	$5Na_2O \cdot V_2O_4 \cdot 11V_2O_5$	1071
Sodium pyrovanadate	$2Na_2O \cdot V_2O_5$	1148
Sodium metavanadate	$Na_2O \cdot V_2O_5$	1166
Beta sodium vanadyl vanadate	$Na_2O \cdot V_2O_4 \cdot 5V_2O_5$	1218
	$Na_2O \cdot 3V_2O_5$	1235
Vanadium pentoxide	V_2O_5	1243
	$Na_2O \cdot 6V_2O_5$	1295
Sodium orthovanadate	$3Na_2O \cdot V_2O_5$	1562
Vanadium trioxide	V_2O_3	3580
Vanadium tetroxide	V_2O_4	3580

Source: Ref 2.

Table 2: Melting point of complex sulfates

Compound	Melting point, F
$K_3Fe(SO_4)_3$	1145
$K_3Al(SO_4)_3$	1210
$KFe(SO_4)_2$	1281[1]
$Na_3Fe(SO_4)_3$	1155
$Na_3Al(SO_4)_3$	1195
$NaFe(SO_4)_2$	1274[1]

Source: Ref 2.
[1]In high-SO_2 atmosphere

Table 3: Melting points in system $MgO-V_2O_5-SO_3$

Material	Melting point, F
MgO	5070
$3MgO \cdot V_2O_5$	2175[1]
$MgSO_4$	2055[2]
$2MgO \cdot V_2O_5$	1535[1]
V_2O_5	1247

[1]Initial melting point [2]Incongruent; dissociates at melting point

cy of olefinic hydrocarbons to oxidize in storage.

■ Water emulsifiers. Suspend water in the oil so the corrosive salts cannot contact system metal. They can also emulsify small amounts of additional water that may result from condensation. Water that settles to the bottom of the tank, however, is best handled by draining when possible.

■ Corrosion inhibitors. Neutralizing and filming inhibitors protect system metal from corrosive attack.

Problems developing during the coal preflame stage are obviously very different from those of the oil preflame stage, but some of the factors that lead to these problems are similar. Primary problems encountered at the coal preflame stage are frozen coal, fugitive dust, coal-pile fires, and coal-pile runoff.

The best way to deal with these problems is a mechanical/chemical combination. The chemical programs currently recommended for the coal preflame area are:

■ Freeze conditioning agents. Actual freeze-point depressants such as glycols are surface-active agents that coat the coal particle and emulsify the surface moisture to minimize the bonding strength of ice crystals that may form.

■ Dust suppression agents. Where water is sprayed on coal to control fugitive dust, wetting agents and water-spray enhancers increase the effectiveness of dust suppression.

■ Coal-pile binders or sealers. These are water-soluble compounds that, after drying, form a crust across the exposed surfaces of a coal pile. The crust will protect the pile from penetration by either water or air for up to 90 days, minimizing fugitive dust loss, coal-pile fires, and coal-pile runoff. Optimum performance is achieved when the compounds are used in combination with a good program of coal-pile compaction.

Combustion stage. In the combustion of either oil or coal, the problems are very much the same. They differ only in degree, depending on the quality of the fuel and the firing method practiced. Key problems are unburned carbon, high excess air, and flyash reinjection (coal only).

Application of a chemical as a combustion catalyst in combination with good mechanical control of optimum excess-air levels can improve the efficiency of both oil and coal firing by minimizing excess air and unburned carbon. Such chemicals as copper and manganese compounds allow more fuel to burn with lower levels of excess air by lowering the activation energy required for the oxidation of carbon. What this means is that carbon ignites at a lower temperature. Because fuel burned in a heat-transfer device like a boiler only has a certain amount of time before it cools below the carbon ignition temperature, the lowering of that temperature increases the time available for the carbon to contact the oxygen and combust. Thus, less excess air is required to achieve complete combustion.

A problem unique to units emitting high unburned carbon materials, like stoker-fired boilers, is that of high maintenance requirements for flyash-reinjection systems. As their name implies, these systems reinject flyash into the furnace to give the carbon in the flyash a second chance to burn. If the flyash passes through a fan enroute to the furnace, its considerable abrasiveness can create a severe maintenance problem. In some cases, the use of a combustion catalyst can eliminate the need for flyash reinjection.

Fireside stage. After combustion takes place in power boilers, potential problems can often become more acute. Deposits in both the high-temperature zone (waterwall tubes, superheater, reheater, and convection pass) and the cold-end (economizer, air heater, fans, and stack) can shorten equipment life due to corrosion and reduced heat transfer (Fig 2).

In the high-temperature zone, deposits are formed as a result of low-melting-point compounds of sodium, vanadium, sulfur, and oxygen impacting tube surfaces in liquid form, as shown in Tables 1 and 2. They either remain in liquid form or solidify once they have deposited on the tube surface. In either case, these deposits are extremely difficult to remove by conventional sootblowers.

Favorable removal of these deposits is possible with the addition of a chemical capable of elevating the melting point and modifying the texture of the deposit. This is most often accomplished with a chemical containing magnesium. When almost any magnesium-bearing compound passes through a flame, it dissociates and recombines with oxygen to form magnesium oxide (MgO).

As shown in Table 3, MgO itself has a melting point of over 5000F. It thus forms preferred high-melting-point compounds with the oxides of sulfur and vanadium. And, finally, MgO has a very friable (crumbly) texture that acts to modify the overall texture of deposits containing significant amounts of magnesium so they are easily removed from tube surfaces.

At the cold-end, problems result from the presence of sulfur trioxide (SO_3), which can combine with water vapor to form sulfuric acid (H_2SO_4). The acid is then available to condense on surfaces having temperatures below the acid

dewpoint. The condensed acid layer is of extremely low pH and is quite sticky. This condition acts to collect flyash on the acid-bearing surfaces. The resulting deposits act to impede heat transfer, and the corrosion limits equipment life.

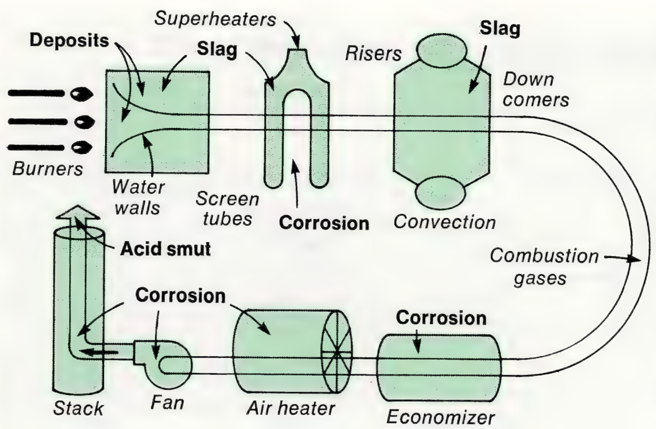
Magnesium and manganese are two generic chemicals that help to solve the SO_3 problem. To understand the role of each, the mechanisms by which SO_3 is formed in flue-gas streams must be understood. When sulfur-bearing compounds pass through a flame, they dissociate and then oxidize to SO_2. A small portion of this SO_2 (1 to 3%) will oxidize further to SO_3. Part of this oxidation will occur in the flame and the remainder at tube surfaces. The portion formed in the flame is the result of SO_2 combining with highly reactive atomic oxygen (O) in the high-temperature environment. The SO_3 formed at the tube surface is the result of vanadium-bearing deposits (V_2O_5), or to a lesser degree iron oxide surfaces (Fe_2O_3) catalyzing the reaction between SO_2 and molecular oxygen (O_2). The resultant concentration of SO_3 determines the acid dewpoint via the relationship shown in Fig 3.

Magnesium can act in two different ways to control cold-end corrosion. When added either to the fuel prior to combustion or to the flue gas in the high-temperature zone, it is available to react with SO_3 to form magnesium sulfate ($MgSO_4$). This reaction reduces the concentration of SO_3 in the cold-end and, therefore, lowers the acid dewpoint.

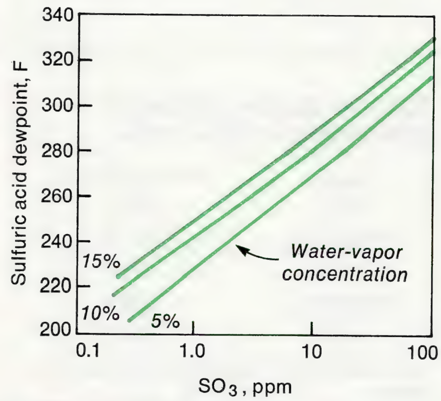
When added either to the fuel or to the flue-gas stream at any point, MgO will be collected on H_2SO_4-laden surfaces and will act to neutralize the deposit mass and render it noncorrosive. This final mechanism can actually be performed by any neutralizing compound available in the flyash stream. In fact, in many coal-fired boilers today flyash serves this purpose.

Manganese has one primary means by which it controls cold-end corrosion. The chemical poisons the catalytic effect of V_2O_5 and Fe_2O_5 at deposit surfaces. Other mechanisms, such as direct reaction with SO_3 and surface neutralization, have been proposed for manganese; at this point, however, the catalytic poisoning effect appears to have the most credence.

Emission stage. The final major area where problems occur in the fuel-burning cycle is in the emission of flue gas from the stack. In oil-fired boilers, the primary problem is acid smut, which is normally defined as carbon particles soaked with condensed sulfuric acid. These particles deposit on neighboring homes, vegetation, and automobiles, and create a severe public-relations problem for industrial plants. Acid smut can also



2. High-temperature and cold-end problem areas are these: *Deposits* consisting of coked fuel and fuel ash; *slag* from ash-forming elements in fuel; *corrosion* caused by SO_3 in flue gas; *emissions* consisting of acid smut; and *plugging and fouling* from flyash adhering to heat-transfer surfaces



3. Effect of SO_3 levels on sulfuric-acid dewpoint. Values of water vapor concentration are calculated at a total system pressure of 760 mm Hg (1 atm)

occur in coal-fired boilers if the plant contains a highly inefficient electrostatic precipitator. Acid-related emission problems are controlled in the same way as cold-end corrosion problems.

The primary emission problem for coal-fired boilers is that of excess particulate emissions due to inefficient electrostatic precipitators. Excess emissions result from a complex combination of mechanical and chemical phenomena. Chemical programs to control the excess normally involve injection of a liquid chemical into the flue-gas stream to improve the collection efficiency of the precipitator.

Fuel-treatment program

In selecting a treatment company to solve fuel-related problems, it is important to keep in mind that chemicals are only tools. In order to be effective, they have to be part of a total control program designed to solve problems in a way that is economically beneficial to the user.

A total fuel-treatment program should be sound in these areas:

■ Technology. The supplier should have a good understanding of the technology of both the cause for the problem and its solution. This includes an understanding of the technology of the equipment in which the fuel is fired.

■ Chemical. The following factors must be considered in purchasing a chemical, and it must be kept in mind that each plays a positive or negative role in the effectiveness of the chemical: stability; pumpability; dispersability; reactivity; side effects; cost effectiveness; and compatibility with the system being treated.

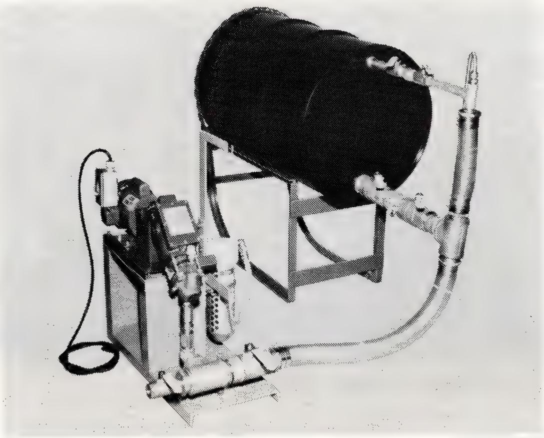
■ Feed systems. Accurate and cost-effective feed rates are ensured when the feed-system design accommodates the properties of both the chemical and the system being treated. In most cases, the lower the cost of the chemical, the higher the cost and sophistication of the feed system. Because of this, the choice of program may often depend on such nontechnical factors as funding alternatives, availability of manpower to maintain equipment, availability of space, etc.

■ Means for demonstrating results. If the benefits of a fuel-treatment program are not measurable or at least clearly visible, there is no justification or accountability for that program. A sound fuel-treatment program includes tests and monitoring to ensure value.

■ Service. A broad definition of service that can be applied to the fuel-treatment area is "anything the supplier of the chemical does to make the system to which his chemical is being applied work more dependably and efficiently." This can involve the chemical program directly or be independent of it.

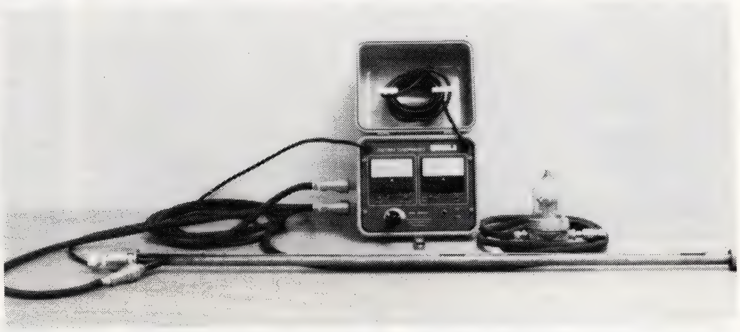
The total program approach can be illustrated by looking more closely at programs for treatment of fireside residual-oil-fired boilers. Through the years, three basic program types have evolved. These types are characterized by the method in which the active ingredients remain dispersed in the carrier fluid. The three categories are organometallics, slurries, and emulsions.

Organometallics, as used in fuel treatment, actually is technically inaccurate as a word that describes any metal-



4. Emulsion treatment requires feed system like that shown at left

5. Acid dewpoint meter identifies dewpoint temperature



bearing compound that is oil soluble. The features of organometallic products are:

- Small particle size of resultant metal oxide (all particles less than 0.1 micron), which yields high reactivity per unit of active ingredient.
- Oil solubility that allows treatment of oil storage tanks as well as fireside problems.
- High package stability that permits long-term storage of product.
- Viscosity characteristics (less than 100 centipoise (cp) at 70F) that allow use of inexpensive and unsophisticated feeding equipment.
- Premium price, which is the result of the high cost of raw materials and sophisticated manufacturing procedures.
- Variable content of active ingredients, which is the result of (1) the limited solubility of organometallic compounds in hydrocarbon carriers, and (2) the manufacturer's discretion in his formulation.

Because of these features, organometallics have most often been used by small plants where combustion-system design warrants highly reactive, multifunctional products, or where the investment in sophisticated feeding equipment cannot be justified by the overall cost of fuel-burning problems.

Slurries are suspensions of inorganic metal oxides or hydroxides in hydrocarbon or water carriers. Key features of slurry products are:

- High metal content, which allows a large quantity of mass to be delivered to the problem area.
- Low cost per pound of metal, which allows still more mass to be fed for the dollar.
- Oil insolubility that limits the feeding location to oil en route to burners or to short-term storage (less than a few hours).
- Higher viscosity (1500 to 5000 cp at 70F), which is a design consideration for feeding equipment that restricts versatility and increases the cost.
- Variable package stability from manufacturer to manufacturer. This suggests potential problems like active ingredients settling in storage, leading to product inefficiency and expensive disposal. The solution is to evaluate this area very closely.
- Variable particle size from manufacturer to manufacturer. Although all slurry particles are larger than organometallic (oil-soluble) particles, slurry particles can vary in size from 0.1 to 50 microns or more. The reactive surface area is therefore highly variable.

Because of these features, slurry programs are most often used in plants where the cost of the problems justifies the investment in more expensive feeding systems, and the boiler design does not preclude the use of large-particle slurry products. An example of such a design would be a gas-to-oil converted boiler with small flue-gas passages.

Emulsion is the final program type. This unique technical approach borrows one of the best features of the organometallics (small particle size) and passes along the cost savings in manufacturing to yield a lower price. Thus, when emulsions are made a part of the total program approach described earlier, the result can be many times over the most effective chemical-treatment program for solving fireside problems in oil-fired boilers.

In the emulsion process, a water solution of a metal-bearing compound is emulsified in a hydrocarbon carrier. The resultant product has the following features:

- Small particle size of the resultant metal oxide (all particles less than 0.1 micron), which yields a high reactivity.
- Much lower price per pound of metal than organometallics, which means more reactivity for the dollar.
- Good package stability (six months or longer), which allows reasonable storage time for the product.
- Higher viscosity (2500 to 6000 cp), which is a design consideration for feeding equipment that restricts feed-system choices and increases feeder cost.
- Oil insolubility that limits the feeding location to oil en route to burners or to short-term storage of the mixture (less than a few hours).
- Variable active-ingredient levels that result from the solubility limits of the metal-bearing compounds in water.

Emulsion programs containing copper or manganese are suitable for improving combustion. Those containing magnesium, manganese, or both, are suitable for deposit and corrosion control. A packaged feed system like that shown in Fig 4 ensures proper chemical application and maximum effectiveness.

To see that the intended result of the fuel-treatment program is achieved, several analytical and monitoring services are offered as part of the emulsion program. Regular analyses of fuel-oil properties are recommended to ensure proper treatment levels and to anticipate problem areas.

Other analyses to consider: (1) fireside deposit tests for troubleshooting the fireside and for reinforcing monitoring results; (2) acid dewpoint and deposition rate studies (see Fig 5), H_2SO_4 condensation tests, and corrosion coupon studies for measuring corrosion tendencies and monitoring the effectiveness of chemical programs in controlling corrosion.

As detailed throughout this article, a variety of problems can exist in the fuel-burning cycle; those arising with coal and residual fuel oil can be costly. A program of good mechanical control, coupled with an effective chemical treatment program, can drastically reduce the cost of these problems.

And, most important, the effectiveness of the chemical-treatment program depends on how well it meets the total program requirements for technology, chemicals, feed system, demonstration of results, and service. ■

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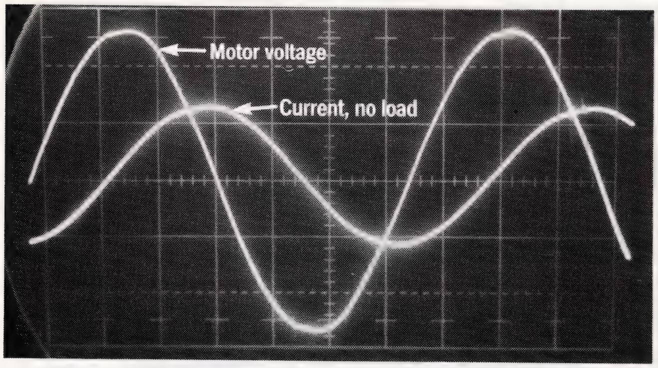
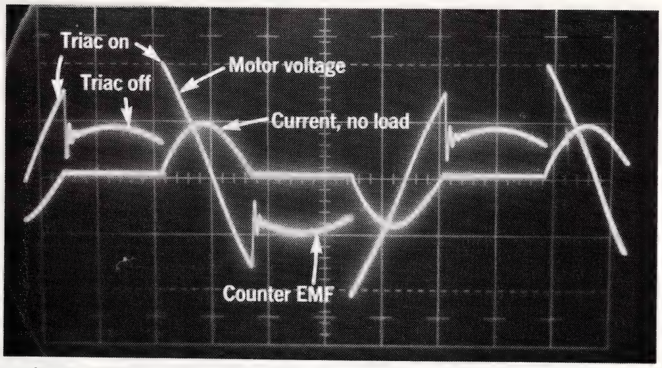




1-2. Phase angle between voltage and current (left) is greatest at no load. PFC (right) cuts voltage, reduces losses

EQUIPMENT DECISION-MAKING

New approaches cut motor kWh use

Most-promising concept appears to be the power-factor controller developed at NASA. The ac synthesizer developed by Exxon Corp is beset by legal problems and is years away from commercial availability, while the Wanlass motor now is aimed at only the three-phase retrofit market

By Eugene F Gorzelnik, Senior Editor, Electrical World magazine

Emphasis on reducing electricity costs has spurred the development of ways to reduce the amount of electricity used by induction motors. Most prominent among these approaches are the power-factor controller (PFC) developed at NASA's Marshall Space Flight Center in Alabama, a recent announcement by Exxon Corp of a new electronic technology for synthesizing alternating current of any desired frequency and voltage, and development of a controlled-torque electric motor by Cravens L Wanlass.

These three approaches are quite different. The PFC reduces losses by sensing the phase lag between voltage and current. This information is fed to an electronic controller, which forces the motor to run at a constant predetermined optimum power factor. The Exxon approach starts with rectified ac power or dc power from a battery that is inverted to produce a synthesized ac power of variable voltage and frequency, which is then applied to control the motor. The Wanlass approach involves maximizing motor efficiency by optimizing the value of a capacitor in series with a motor's main winding, and the presence of a control winding.

Power-factor controller

The PFC was developed as a result of a need to reduce the amount of energy consumed by motors used in a solar-heated and solar-cooled demonstration house at the Marshall Space Flight Center (MSFC). Its improved efficiency results from less energy being wasted within the motor, primarily during light loading.

According to Frank J Nola, who developed the PFC at NASA, the unit detects the workload on a motor by sensing the phase relationship between the voltage and current (the power factor) applied to the motor. When the PFC senses a light load (Figs 1 and 2), it reduces the applied voltage to the motor by means of a solid-state switch (triac). As the load is increased (Figs 3 and 4), the device automatically increases the applied voltage to satisfy loading conditions and to maintain constant speed.

By applying to the motor only the voltage that is required for a given load, wasted energy is reduced. Because the PFC attaches to the lead wires of the motor and not in the motor itself, it can be applied to existing motors without motor modification. In addition, there is no sacrifice in performance, and speed change is less than 2%.

The PFC has been tested at MSFC on about 50 motors, both single- and three-phase, ranging from 1/12 to 5 hp (see table). The applications tested include drill presses, bench grinders, flaring machines, fans, pumps, typewriters, and major home appliances.

Typical energy savings, Nola says, range from 5 to 50%, depending on loading conditions. In more-expensively-built motors operating at rated load and rated voltage, he observes, there may be no

Estimating potential energy savings nationwide

	Millions of units	Per-unit savings, W	Duty cycle, hr/day	Total power savings, million kWh/day	Total fuel savings, bbl/day
Typewriters	5	30	8	1.2	2000
Industrial sewing machine	1	60	16	0.96	1600
Washing machine	50	36[1]	1[2]	1.8	3000
Dryer	35	55	1	1.9	3200
Refrigerator	50	13	10	6.5	11000
Freezer	25	17	10	4.25	7000
Fan	10	25	10	2.5	4000

At $14/bbl, the total savings are $445,000/day. Savings to utilities and from air conditioning are not included. Fuel calculations are based on an energy conversion of 600 kWh/bbl [1]Units are Wh [2]Units are load/day

PEOPLE IN THE FOREFRONT

Coal: Mine it, don't undermine it

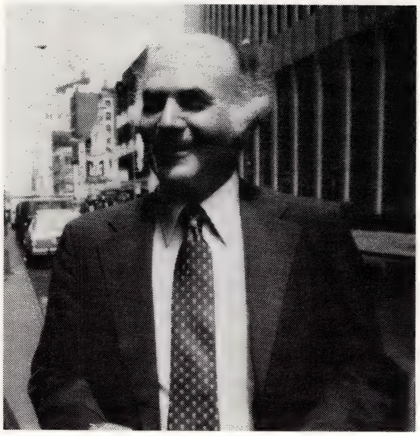
Federal policy now hinders industry's transition to coal. This consultant explains how, proposes changes, and offers advice to energy planners

The uncertain availability and cost of future energy sources are frustrating America's industrial decision-makers. Confused by contradictory national energy, environmental, and economic policies, large energy users are finding it harder to choose confidently among oil, gas, coal and waste as the fuel for generating power in future plants (box, below).

What's worse, that frustration and confusion may become an epidemic, according to Jerry Gambs, a vice-president at the New York City-based consulting engineering firm of Ford, Bacon & Davis Inc. He foresees more smaller industrial energy users facing the same tough choice because "individual plants must look more and more to standby power systems to protect at least some of their load."

By way of explanation, Gambs predicts that, "in the next 10-20 years, industry will face two serious shortages—a shortage of electric power from utilities and a shortage of petroleum products used to generate steam." Proven technology can help industry cope with both shortages, but only if Washington recognizes the dependence of America's economic future on a realistic national energy plan.

The utility shortfall, says Gambs, should begin to affect industry within the next two to four years on a regional basis. First to be hit will be those areas that depend heavily on nuclear power. Eyeing today's frequent shutdowns of operating nuclear reactors and delays in the licensing of new plants, Gambs expects that "more frequent brownouts



and blackouts in the 1980s will mean that industrial plants will have a difficult time operating as they've been used to, with sufficient electric power."

Add capacity—and use it

His solution: Install more diesel- or gas-turbine-based standby generating capacity in industrial plants. Those units, argues Gambs, need not sit idle, waiting for a power failure; they can be used in the interim for peak shaving if the plant's electric load varies over a 24-hr period. Gambs adds that such a scheme is already in operation at several plants in the US.

To cope with shortages of petroleum used to generate steam, Gambs recommends cogeneration because it kills two birds with one efficient stone. By passing the hot exhaust gas from a diesel engine or gas turbine through a heat-recovery boiler, a plant can meet its steam requirements "for free" while satisfying part of its electrical demands. And, by adding a steam turbine downstream of the boiler in a combined-cycle configuration, surplus electricity can be produced while extracting additional Btus from expensive fuel.

Unfortunately, today's diesels and gas turbines burn oil or gas, so Gambs further recommends that designers of new industrial plants consider coal-fired cogeneration "as a first alternative" where environmental standards allow it. He, and Ford, Bacon & Davis, are particularly high on atmospheric fluidized-bed boilers because "they are both high in efficiency and can satisfy emissions requirements for SO_2 and NO_x."

Coal is not a panacea, however. Gambs urges industrial energy planners to weigh several aspects of coal use before making any decisions. Compared to oil, coal certainly makes sense in terms of availability and price. "We already have a global shortage of oil, with demand exceeding supply by almost 2-million bbl/day, out of the free world's daily consumption of 51-million bbl," reports Gambs. He expects this situation to continue, and therefore sees oil prices continuing to skyrocket.

Obstacles facing coal

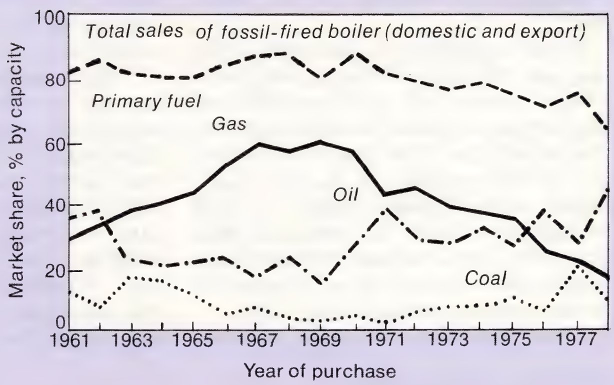
Coal, on the other hand, now is roughly one-third the price of oil, on a \$/million-Btu basis. As for the future, Gambs states, "I don't believe that the price of coal is going to track anywhere near the price of oil. It hasn't in the recent past, and in the future it probably will cost even a smaller percentage of the price of oil as crude escalates in price."

Despite favorable outlooks for coal

Boiler buyers high on waste, fickle on coal

Orders for fossil-fired steam generators have declined since 1970, when they accounted for 87.2% of all purchases (right). Area above the top curve represents the capacity of units ordered that are designed to burn waste fuels. Reasons for the decrease in sales of fossil-fired boilers include: (1) conflict between fuel-use and environmental laws, (2) general slowdown is the US economy, and (3) energy conservation in industrial process plants.

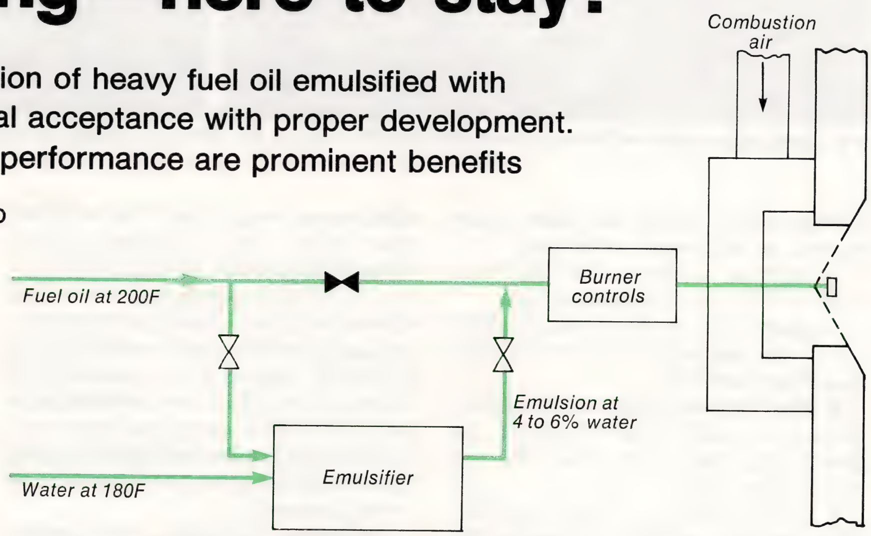
Orders for coal-fired boilers peaked at 19.8% in 1963, but then declined to a low of 1% in 1971, one year after passage of the Clean Air Act. Since then, market share has roller-coastered back to its traditional average of 9.4% last year.



Emulsion firing—here to stay?

Recent studies in the combustion of heavy fuel oil emulsified with water could lead to commercial acceptance with proper development. Fuel savings and better boiler performance are prominent benefits

By E A Holden, General Foods Corp



1. Emulsifier system is installed in a cabinet near the burner front. Switch from straight oil firing to emulsion firing is actuated by pushbutton

In the area of combustion, attention has been directed recently to oil-burner developments using low excess air to improve burner performance. One method that has gained increasing popularity is the combustion of heavy fuel oil emulsified with water.

Research and development in emulsion firing has been largely prompted by university studies and US government-agency grants. In Europe, the French, the Russians, and the Danes are likewise engaged in emulsion studies and associated equipment development. The Canadian Combustion Research Laboratory in Ottawa is now testing a Canadian-built emulsifier.

With water emulsified in heavy fuel oil, research has shown that fuel-oil atomization is improved by the microexplosions of entrained water as the emulsion enters the combustion chamber. Finer atomization thus provides expectations of improved combustion with less carbon loss, less excess air, and perhaps better heat transfer.

Fuel-oil/water emulsification is a homogenization process. Some of the equipment is conventionally used to homogenize food products such as milk. Emulsifiers may be classified as: (1) positive displacement pumps that discharge the mixture against an impact ring, (2) centrifugal pumps that discharge the mixture through atomizing nozzles, and (3) high-frequency cavitation devices activated by a resonant generator. In principle, these devices apply *shear* to reduce water particle size and *cavitation* to achieve uniform distribution of water particles throughout the oil.

An emulsifier system is installed in a cabinet that is placed near the boiler front. Oil piping to and emulsion piping from the cabinet are shown in Fig. 1. A change from straight-oil firing to emulsion firing and vice versa is activated by a pushbutton mounted on the front of the cabinet, along with pertinent instruments and annunciator lights. When off-normal conditions occur, interlocks automatically revert flow from emulsified oil to straight oil.

The typical physical specifications for an emulsified heavy (No. 6) fuel oil are the following:

- Water particle size, 5 to 10 microns distributed uniformly throughout the oil.
- Water, 4-6% by volume.
- Water temperature, 180F.

The benefits claimed with emulsion firing include:

- *Improved combustion.* Microexplosions of emulsified water superatomizes the heavy fuel oil. The minute particles therefore undergo earlier ignition, as would be expected with lighter oil grades.
- *A shorter flame.* Combustion is completed with less residence time in the furnace.
- *Less excess air.* With finer atomization and a shorter flame, less air is required to reach and to envelop flame tailings.
- *Less carbon loss.* More complete burnout of carbon occurs due to superatomization and a shorter intense flame.
- *Improved boiler efficiency.* This is mainly due to reduced excess air and a cleaner boiler.

A benefit not usually mentioned is the probability that emulson firing may replace or supplement the use of fuel-oil additives. Various additives are touted as a means of improving combustion, of reducing slag accumulations, and of controlling boiler back-end and air-preheater corrosion. Fuel-additive benefits, therefore, parallel expectations from emulsion firing, especially the claim for improved combustion.

Slag reduction. For the case of a cleaner boiler, trials at one industrial plant over a period of several weeks with emulsion firing showed that heavy slag, which had developed during straight-oil firing, actually disappeared from the generating tubes. These trials were conducted with 17% emulsion. The dusty deposit that remained after a month's continuous service with emulsion firing was white/grey in color and measured 1/16-3/32 in. thick. Sootblowing was minimized,

Key operating conditions for straight and emulsified oils

Conditions	Straight oil	Emulsified oil
Excess air, %	20	20
Boiler exit-gas temp, F	500	500
Fuel-oil temp, F	200	200
Water temp, F	—	180
Emulsion water, %	—	5
Oil, Btu/lb	18,500	18,500
Emulsion, Btu/lb	—	17,575
Ambient-air temp, F	80	80

that its fuel sources would be cut off. All the fuel used in its war machine was from coal converted to synthetic fuels; Cost was not a major consideration. Today, the technology exists to liquefy coal, but at a cost. The big push should be toward reducing this cost to an economic figure and toward developing a large enough synthetic-oil industry to have a significant impact on the level of imports.

Significantly, almost on the same day that POWER was discussing this need with Leathers, West Germany's Chancellor, Helmut Schmidt was expounding the use of German coal as the first national priority for the 1980s. Coal, which presently accounts for 28% of the energy consumed in Germany, vs 18% in the US, is heavily subsidized by the government, and Schmidt says that this subsidy would rise to more than $3-billion a year. "We are doing this," says Schmidt, "because coal, although more expensive, is the only important source of energy that allows us to be independent of foreign decisions."

And Leathers agrees: "You've got to get started. You're better off laying out a big subsidy for energy and keeping the dollar strong and the balance of payments up."

Thinking energy balance

"All industry and government schemes should be considered in terms of the total energy balance—how much useful energy is consumed or produced at every stage in the cycle. This information is available and it's a shame to have people making policy decisions without looking into it—or without even understanding it. That's why I'm so damned upset with those gasahol nuts," says Leathers. He points out that it takes more than twice as many Btus from various fuels to produce gasahol, as there are useable Btus in the fuel.

He emphasizes that problems with total energy balance are not new. "Way back in the industrial revolution, counterproductive laws were passed by the British government because there was no understanding of total energy balance. For instance, when it was noted that forests were being depleted to build houses, a decree was passed that all houses should be built of bricks. But it took more wood in the form of fuel to make bricks than it would to build houses; so Britain lost her forests anyway."

With the same energy-balance ideas in mind, Leathers takes out time from running a modern petrochemical facility to consider the energy problems involved in such basic endeavors as agriculture. "What's the net energy involved in corn production?" he asks. Through a gasification process, both energy to operate harvesting machinery and fertilizer could be obtained from the stalks and husks (stover) left after the corn is reaped. Given a fixed number of acres, could the stover be used to obtain a net energy balance without additional fuel input?" he asks.

"Everything has an energy component that must be considered in the total balance," Leathers points out, explaining that there are two basic forms of energy: *transient*, as experienced in a combustion process, and *formative*, that energy needed to create a material or component from raw materials. Energy balances that consider both types uncover the flaws in many proposed "solutions" to the energy crisis.

"There's a lot of talk about hydrogen as a fuel," he asys, "but you can calculate that if the hydrogen were free at the source; you'd need all the energy it contains just to pump it to the users." Geothermal energy has the same problems. "If you had geothermal water at 400F, you'd only use it if no other power source was available. Usually this water is found in arid areas, where the only available heat sink would be an air-cooled condenser. With isobutane as the working fluid, you might be able to extract 13% of the Btus as useful energy—9% by the time it was electricity.

Solar energy is of such low quality that the formative energy capital needed to build a solar plant could not easily be amortized by the transient energy that the plant generates. Leathers considers that passive solar systems or, more realistically, buildings designed to take account of solar energy in the total energy cycle, are a more profitable way to go.

Algae cultivation is another alternative being considered at Dow. A research group investigated the cultivation of an algae species containing the largest amount of sugar and protein, with the idea of fermentation and alcohol production. Results of the investigation showed that algae could not be grown and harvested at a net energy surplus. Leathers says, however, that if the algae is available anyway, it could be gasified to produce energy. "I've now got them looking at blue-green algae. This algae grows so fast in parts of the South that you can almost walk on it. I want to see if you can cultivate and gasify it with a net energy gain."

"The same considerations apply to burning garbage. If you've got to collect and transport the stuff anyway, you can make a case for burning it as a fuel. But, if you count the Btu cost of making garbage, the balance is ridiculous. You know those plastic glasses you get with your drink on an airplane? Well, just as an example, you can calculate that it costs 50,000 Btus just to get one pound of these plastic glasses on the plane." ■

Want a cleaner oil-fired boiler? Just add water

If you still think that oil and water don't mix, think again. A growing number of industrial energy users now substitute emulsions—homogenized mixtures of heavy oil and water—for 100% heavy oil to fuel their boilers. Among the reported benefits of the changeover: reductions in burner excess-air requirements and slag accumulations, and concomitant increases in boiler efficiency.

One believer in emulsion firing is Ed Holden, an engineering consultant at General Foods Corp's Technical Center in Tarrytown, NY. For the past few years, Holden and other engineers have been studying the effects of burning oil/water emulsions in industrial boilers at General Foods plants and elsewhere. His conclusion: "From past experience, it appears that boilers burning emulsions can stay cleaner than those burning straight oil. That means less sootblowing and lower maintenance costs at the end of the year."

Where have all our engineering leaders gone?

Never before has energy decision-making demanded as much broad insight as it does today. It takes leadership to address all the tough issues—be they environmental, economic, legal, or social—that face industrial energy users in a world of increasing complexity.

Engineering still determines the success or failure of any energy decision, however, so industry needs engineering leaders more today then ever. Their assignment is difficult: To find the optimum solutions to energy problems that may be obscured by nontechnical considerations. Will such a new breed of engineers arise and take charge, or will we suffer yet another shortage—that of innovative energy-systems planners? One man who has doubts about the current status of engineering leadership in American industry is Frank Feeley, an engineering consultant to Olin Corp's Chemicals Group.

"Leadership in engineering," claims Feeley, "has deteriorated in my working lifetime." His view is that today's graduates lack dedication to a career in engineering; instead, they aspire to more glamorous nontechnical positions. "To a

On-site generation can be attractive

Peak shaving is compatible with and complementary to most electric-utility operations. Here are the conditions under which it becomes economically attractive for industry

By Stephen H Burch, On-site Power Consultants

On-site power generation is now becoming economically attractive under certain conditions, because of substantial recent increases in electric rates. The data presented here are for high-speed (1800-rpm) diesel/generator sets in the 100-to-1000-kW range. The concepts apply to gas engines, turbines, and slow-speed diesels, but the economics will be different. The data apply to well-engineered, well-constructed, and well-maintained installations. Lack of experience in the design, application, or operation can result in significantly increased operating costs.

On-site peak shaving is defined as "the use of an on-site generator set to complement the electric utility in minimizing overall electric costs by reducing peak demand." As such, it is a demand-management tool, and the generation of kWh is intentionally held to the minimum practical level necessary to achieve the desired reduction in peak load.

The term, cogeneration, is used as defined in the National Energy Policy Act of 1978: A cogeneration facility produces "electric energy, and steam or other forms of useful energy, which are used for industrial, commercial, heating, or cooling purposes." This use is essentially identical to the old term "total energy." Cogeneration is an energy-management tool, whose economics derive from the recovery and use of heat normally rejected in the generation process. These economics generally apply only for base-load or intermediate-load generation.

It is significant that there is no mention of a utility intertie in this definition of cogeneration. It thus conflicts with a second use of the term cogeneration, which is applied to on-site generation systems that are electrically paralleled with the utility system, whether or not rejected heat is recovered.

The heart of an on-site generation system is the engine/generator set. This unit is substantially identical for both peak-shaving and cogeneration. The housing, air intake, fuel, and lubrication systems are also similar, although they may be slightly more substantial for cogeneration, owing to the requirements of continuous operation. Control systems for both on-site-generation approaches are similar in hardware, but very different in software. All these differences are minor, however, relative to differences in cooling and exhaust systems, which define and differentiate cogeneration.

In peak-shaving systems, which are used for relatively few operating hours, there is seldom any economic merit in attempting to recover output heat. With cogeneration, however, elaborate heat-recovery systems may be employed, although such equipment can double the cost. Its benefit, of course, is that it can cut the net heat rate by 50% or more.

Capital and operating costs

An installed peak-shaving system will generally cost between $200 and $350/kW. The list price for a diesel/generator set is roughly $125/kW. The controls and other ancillary equipment may range from $25 to $100/kW.

The most unpredictable variable is installation and site work. An installation in a hospital, computer center, or office building, for instance, may well exceed $300/kW; a system that can be placed in the boiler room of an existing plant, with fuel and electrical interfacing readily available, might cost less than $200/kW.

Installed cogeneration systems typically cost from $300 to $600/kW, with the primary difference being the cost of the heat-recovery systems. Almost every item required in a peak-shaving system will also exist in a cogeneration system—and it may be more expensive, because of redundancy and continuous operation.

Operating costs include fuel, maintenance, and repair. Table 1 summarizes the major components of operating cost for on-site diesel generation. For a peak-shaving system, it assumes that No. 2 diesel fuel (135,000 Btu/gal) can be purchased in bulk for 70¢/gal, for an energy cost of about $5/million Btu and a fuel cost of 5-6¢/kWh, depending on heat rate. Maintenance and repair costs vary widely, but are generally in the range of 1-2¢/kWh. These numbers include a sinking fund for overhaul of the engine/generator set between 10,000 and 20,000 hours.

This article considers cogeneration from an electrical perspective. Thus, its economics are expressed on a kWh basis, with a credit for heat recovery reducing the net cost of electric generation. The alternative is to look at cogeneration as a source of heat, with the byproduct, electricity, reducing the net cost of that heat.

Operating costs for cogeneration systems are significantly lower than for peak shaving. Net fuel costs are lower because of (1) the credit for rejected heat recovered, (2) the lower prices on larger quantities of fuel purchased, and (3) improved fuel consumption resulting from better operating conditions. Maintenance costs are also slightly lower, owing to favorable operating conditions and longer running hours.

Net fuel costs for diesel cogeneration are 2-4¢/kWh. Gross fuel costs are 4-6¢/kWh, but are reduced by a heat-recovery credit of 1-3¢/kWh. The value of the heat-recovery credit depends on the amount of heat recovered, the cost of the replaced fuel, and the efficiency of the replaced heat load.

System economics

Given relatively predictable operating costs for on-site generation, the system chosen and its operating savings depend critically on the local utility's rate schedule and the industrial customer's load profile.

Peak-shaving is most likely to be economically attractive where the utility has a high peak-demand charge and the customer has a poor load factor. Flattening the load profile, of course, reduces the peak demand charge. But since the utility energy charge is virtually always lower than the generator-set operating cost, there is an economic loss on every kWh generated. Operating methods and equipment selection, therefore, should

British thermal units: The future currency standard

Political and corporate decision-making must be based on an understanding of the fundamental nature of energy

The second law of thermodynamics is the guiding principle behind all energy decisions at Dow Chemical Co. Levi Leathers, vice president of manufacturing & engineering technology, explains: "Energy cascades down from its high temperature source, passing through various processes until it reaches a first-law state. We are concerned with the useful parts of the cycle. But we cannot ignore the other parts."

So fundamental is energy to human endeavors that Leathers believes a comprehensive energy accounting system on a national, or even a worldwide scale, could largely replace conventional economics with all its problems of standards and exchange rates. He points to the work of economist Dr Wassily M Leontief, Nobel Prize winner, 1973, whose input-output matrix system places an economic value on all commercial production activities. "Energy," says Leathers, "would be a much more realistic standard for comparison."

Leathers points out that the British thermal unit is free of currency problems and inflation. "Different countries may achieve different heat rates, but this is a reflection of their true efficiency. In this respect many European plants are more advanced than American, because they have long faced high energy costs. They never had a fictitious energy price."

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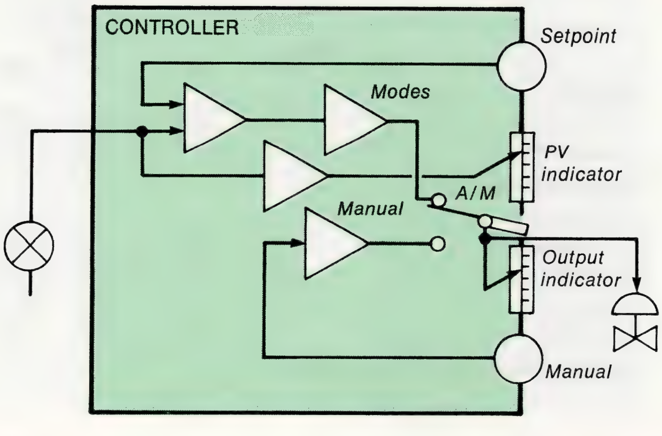

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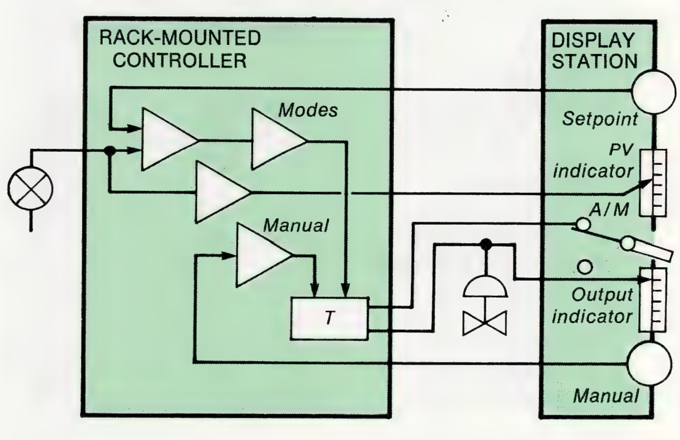

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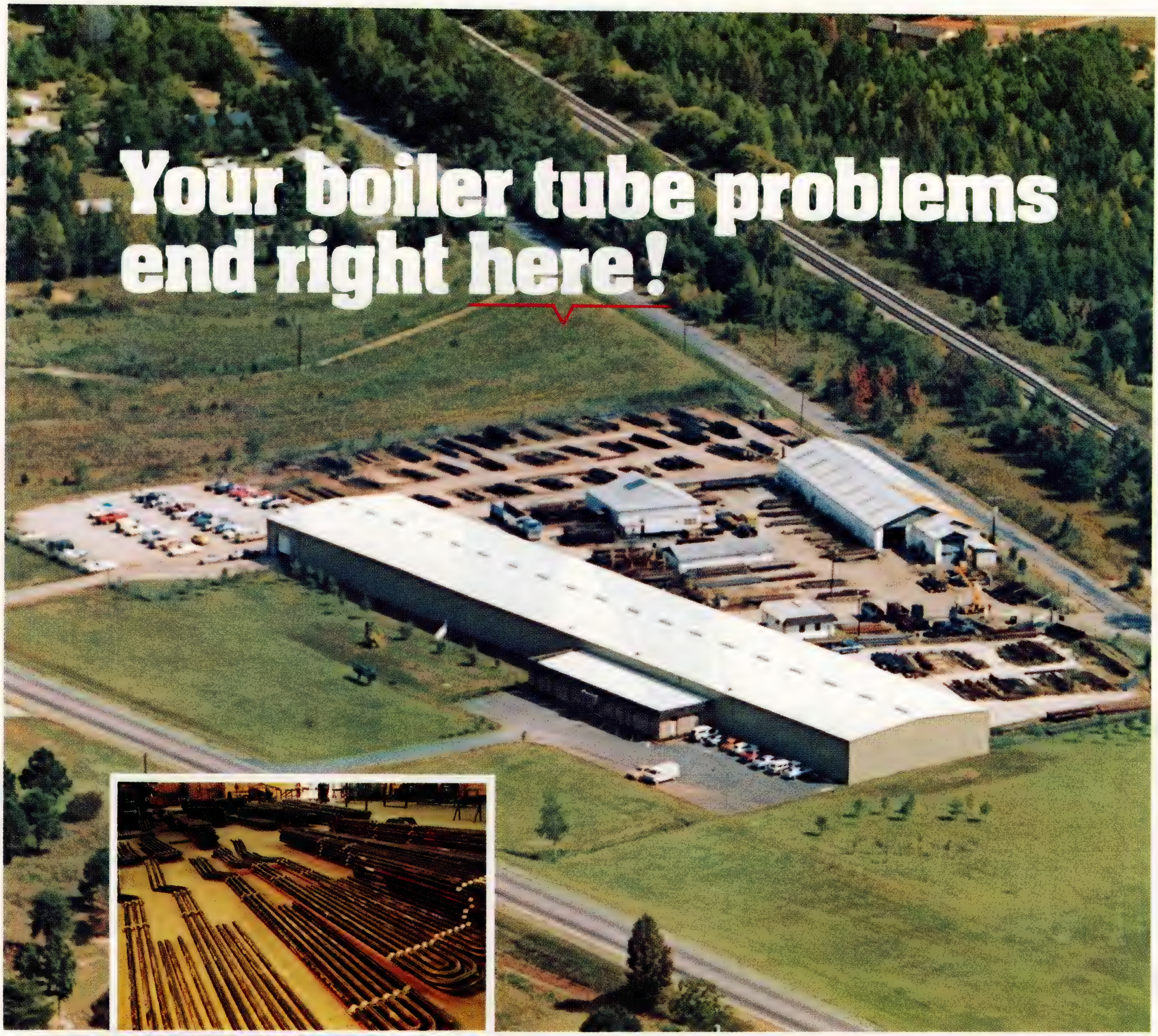

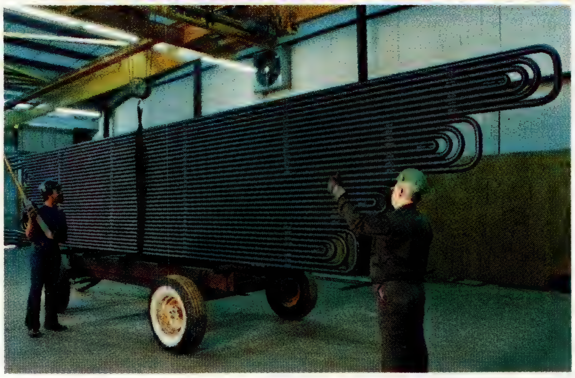

Boiler Tube Company, Lyman, SC

Top: Bending Shop adjoins the fully coordinated ASME Code Weld Shop for in-line fabrication of all types of units.

Below: All fabricated units are thoroughly tested before shipment. Plant has close access to interstate highways for fast dependable delivery.

This is Boiler Tube Company of America's ultra-modern facility — over 50,000 square feet of manufacturing space equipped to provide everything from simple replacement pressure tubes to code-assembled superheaters, panel walls, burner openings, generating tubes and economizers.

Here also is the largest boiler tube warehouse in the country, carrying at all times a complete range of carbon, alloy and stainless pressure tubing, in standard and heavy wall specifications.

Manned by tube bending specialists and expert welders qualified to meet ASME Code standards, Boiler Tube Company responds *fast* to emergency problems — and serves many major companies and utilities on a "standby" basis for preventive maintenance.

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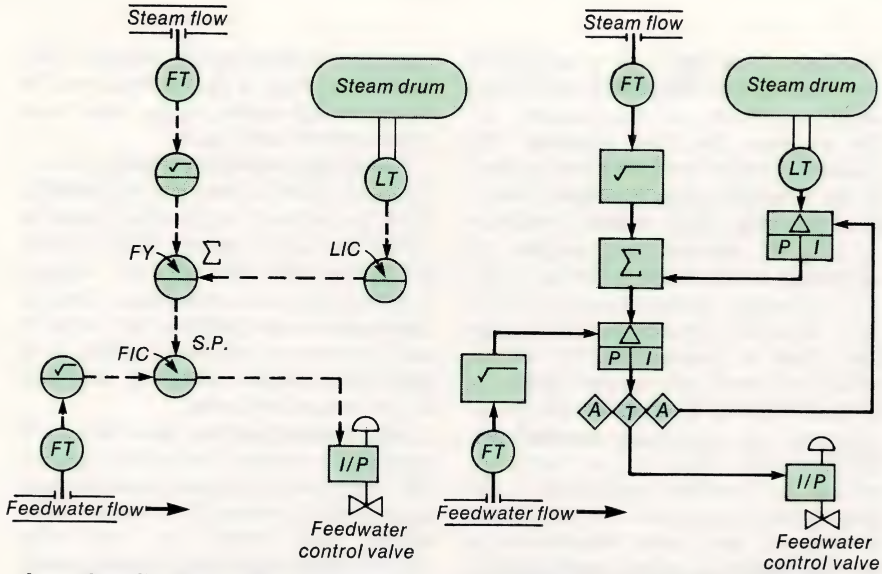
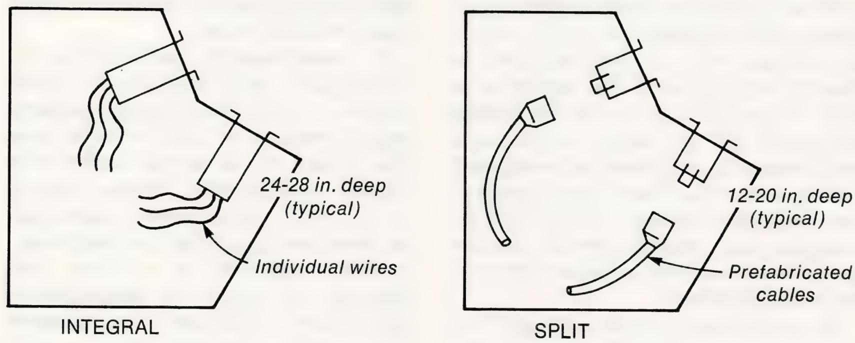


Loop described using ISA symbology **Loop described using SAMA symbology**

4. Integral configurations normally are developed using ISA symbology (left), split systems using SAMA procedures (right). A three-element feedwater loop is shown

5. Control design opportunities are greater in split-architecture systems because operator stations have less depth than complete integral controllers

Front and rear access required **Front access only**



niques that are infrequently encountered in process plants.

Loop complexity. If plant policies do not lead to a clear preference for boiler-control-system architecture, control-loop complexity often becomes the dominant factor in determining which class of instruments will be more advantageous for a particular application. The simplest control loops are those with single inputs and outputs, which implement standard feedback algorithms. Complexity increases when these needs exist: (1) nonlinear or other auxiliary intervening functions, (2) dependence on several measurements to yield inferred process variables such as mass flow rate, (3) requirements for interlocks or control transfers based on changes in process conditions, and (4) use of multiple outputs to manipulate such variables as fuel and air flows at the same time. For example, a simple oil- or gas-fired boiler can easily be controlled with an integral architecture system, while a pulverized-coal-fired unit might be more readily instrumented with a split system.

Integral controllers are generally favored for the simpler loops. Unitized devices, designed specifically for the required function, offer smaller numbers of components and simpler installations. The result is lower design and documentation effort, higher reliability, and more compact mounting spaces.

As additional tasks are incorporated in a control strategy, particularly functions requiring no direct operator intervention, split architecture becomes more advantageous. Benefits are obtained due to flexibility in selecting only essential modules, and in locating hardware without interfaces in high-density racks away from the control room.

Industrial boilers tend to have complex loops with multiple controllers, but with relatively few operator indicators or adjustments. On this basis, a split architecture would seem to be favored. The total number of such loops is small, however, so in a plant otherwise dominated by integral-architecture instrumentation, the benefits could be easily outweighed by the disadvantage of introducing a different class of equipment in the boiler house.

Reliability costs. Reliability is inherently higher in integral than in otherwise comparable split systems because of fewer components and connections. The difference decreases in significance as loops become complex, because of the larger number of cross-connections and intervening devices that must be used even in integral systems.

In simple loops, integral hardware is less expensive because of fewer components. In complex multiple-element applications, the hardware cost advantage is reversed—split systems are less expensive because components can be selected for required computing functions.

Installation of integral instrumentation also tends to be less expensive for simple loops because there are fewer devices to mount and interconnect. In complex loops, installation of split equipment can be less costly if standard cables are available for linking the two sets of components.

Mixed architecture. Some control specialists advocate mixing integral and split architecture, using the former for simple loops and the latter for strategies involving extensive multiple-signal calculations. The approach offers certain advantages for optimizing hardware in boiler applications.

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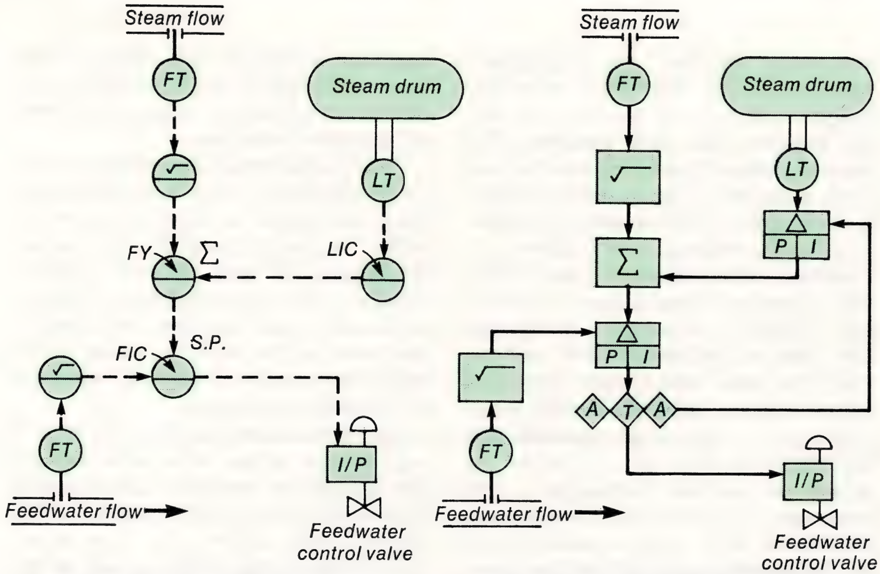
Subjectivity and selection

The instrumentation industry reveals a history of dilemmas, few of which have ever been resolved—and even then not completely. The pneumatic-vs-electronic argument can still be heard. The live-vs-null-zero controversy is solved for the moment, but new electronic technologies have caused its revival in some quarters. The various standard-range discussions seem to have abated in favor of a universal 4 to 20 mA, but, because of intrinsic safety and emerging semiconductor technologies, suggestions are being made for a new examination of the situation. The integral-vs-split question is unlikely to be settled with a single answer either.

For simple process loops, such as two- or three-mode pressure or level control, integral architecture seems to be the obvious choice. For complex loops, such as those found in large-scale combustion control systems, the split approach appears to be the best. Industrial boilers fall between the extremes. The availability of two classes of instruments gives the control specialist the opportunity to make a selection—on a total system or an individual loop basis—with which he can optimize the cost effectiveness of the result. ■



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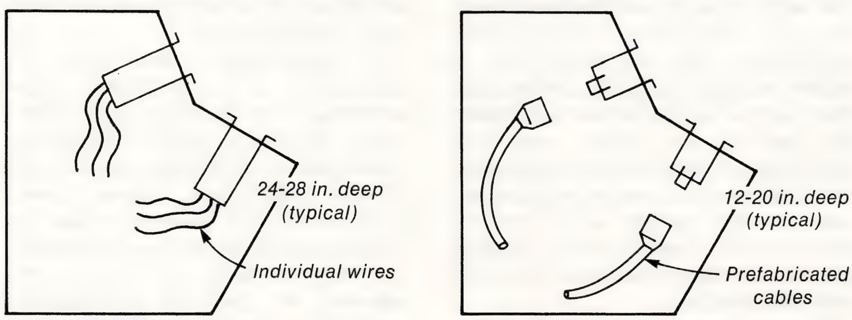

INTEGRAL SPLIT

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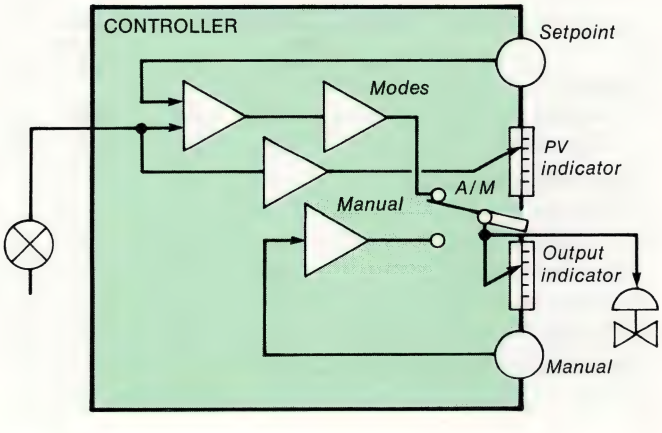

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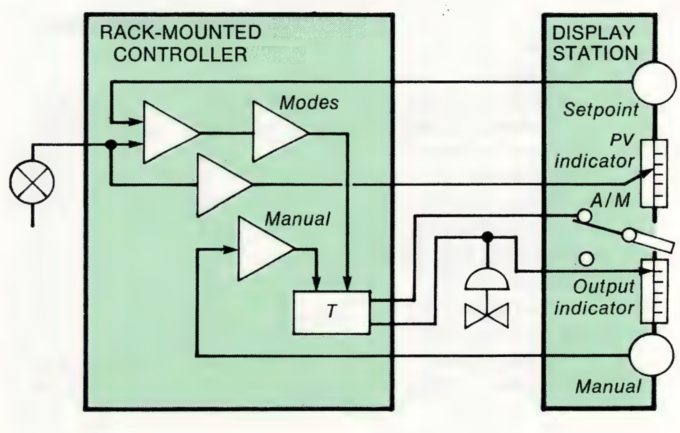

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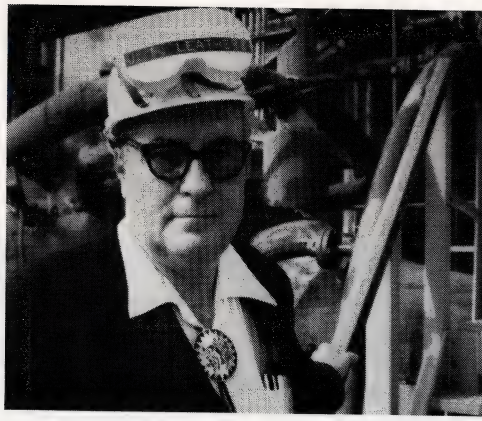
British thermal units: The future currency standard



Political and corporate decision-making must be based on an understanding of the fundamental nature of energy

The second law of thermodynamics is the guiding principle behind all energy decisions at Dow Chemical Co. Levi Leathers, vice president of manufacturing & engineering technology, explains: "Energy cascades down from its high temperature source, passing through various processes until it reaches a first-law state. We are concerned with the useful parts of the cycle. But we cannot ignore the other parts."

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On-site generation can be attractive

Peak shaving is compatible with and complementary to most electric-utility operations. Here are the conditions under which it becomes economically attractive for industry

By Stephen H Burch, On-site Power Consultants

On-site power generation is now becoming economically attractive under certain conditions, because of substantial recent increases in electric rates. The data presented here are for high-speed (1800-rpm) diesel/generator sets in the 100-to-1000-kW range. The concepts apply to gas engines, turbines, and slow-speed diesels, but the economics will be different. The data apply to well-engineered, well-constructed, and well-maintained installations. Lack of experience in the design, application, or operation can result in significantly increased operating costs.

On-site peak shaving is defined as "the use of an on-site generator set to complement the electric utility in minimizing overall electric costs by reducing peak demand." As such, it is a demand-management tool, and the generation of kWh is intentionally held to the minimum practical level necessary to achieve the desired reduction in peak load.

The term, cogeneration, is used as defined in the National Energy Policy Act of 1978: A cogeneration facility produces "electric energy, and steam or other forms of useful energy, which are used for industrial, commercial, heating, or cooling purposes." This use is essentially identical to the old term "total energy." Cogeneration is an energy-management tool, whose economics derive from the recovery and use of heat normally rejected in the generation process. These economics generally apply only for base-load or intermediate-load generation.

It is significant that there is no mention of a utility intertie in this definition of cogeneration. It thus conflicts with a second use of the term cogeneration, which is applied to on-site generation systems that are electrically paralleled with the utility system, whether or not rejected heat is recovered.

The heart of an on-site generation system is the engine/generator set. This unit is substantially identical for both peak-shaving and cogeneration. The housing, air intake, fuel, and lubrication systems are also similar, although they may be slightly more substantial for cogeneration, owing to the requirements of continuous operation. Control systems for both on-site-generation approaches are similar in hardware, but very different in software. All these differences are minor, however, relative to differences in cooling and exhaust systems, which define and differentiate cogeneration.

In peak-shaving systems, which are used for relatively few operating hours, there is seldom any economic merit in attempting to recover output heat. With cogeneration, however, elaborate heat-recovery systems may be employed, although such equipment can double the cost. Its benefit, of course, is that it can cut the net heat rate by 50% or more.

Capital and operating costs

An installed peak-shaving system will generally cost between $200 and $350/kW. The list price for a diesel/generator set is roughly $125/kW. The controls and other ancillary equipment may range from $25 to $100/kW.

The most unpredictable variable is installation and site work. An installation in a hospital, computer center, or office building, for instance, may well exceed $300/kW; a system that can be placed in the boiler room of an existing plant, with fuel and electrical interfacing readily available, might cost less than $200/kW.

Installed cogeneration systems typically cost from $300 to $600/kW, with the primary difference being the cost of the heat-recovery systems. Almost every item required in a peak-shaving system will also exist in a cogeneration system—and it may be more expensive, because of redundancy and continuous operation.

Operating costs include fuel, maintenance, and repair. Table 1 summarizes the major components of operating cost for on-site diesel generation. For a peak-shaving system, it assumes that No. 2 diesel fuel (135,000 Btu/gal) can be purchased in bulk for 70¢/gal, for an energy cost of about $5/million Btu and a fuel cost of 5-6¢/kWh, depending on heat rate. Maintenance and repair costs vary widely, but are generally in the range of 1-2¢/kWh. These numbers include a sinking fund for overhaul of the engine/generator set between 10,000 and 20,000 hours.

This article considers cogeneration from an electrical perspective. Thus, its economics are expressed on a kWh basis, with a credit for heat recovery reducing the net cost of electric generation. The alternative is to look at cogeneration as a source of heat, with the byproduct, electricity, reducing the net cost of that heat.

Operating costs for cogeneration systems are significantly lower than for peak shaving. Net fuel costs are lower because of (1) the credit for rejected heat recovered, (2) the lower prices on larger quantities of fuel purchased, and (3) improved fuel consumption resulting from better operating conditions. Maintenance costs are also slightly lower, owing to favorable operating conditions and longer running hours.

Net fuel costs for diesel cogeneration are 2-4¢/kWh. Gross fuel costs are 4-6¢/kWh, but are reduced by a heat-recovery credit of 1-3¢/kWh. The value of the heat-recovery credit depends on the amount of heat recovered, the cost of the replaced fuel, and the efficiency of the replaced heat load.

System economics

Given relatively predictable operating costs for on-site generation, the system chosen and its operating savings depend critically on the local utility's rate schedule and the industrial customer's load profile.

Peak-shaving is most likely to be economically attractive where the utility has a high peak-demand charge and the customer has a poor load factor. Flattening the load profile, of course, reduces the peak demand charge. But since the utility energy charge is virtually always lower than the generator-set operating cost, there is an economic loss on every kWh generated. Operating methods and equipment selection, therefore, should

that its fuel sources would be cut off. All the fuel used in its war machine was from coal converted to synthetic fuels; Cost was not a major consideration. Today, the technology exists to liquefy coal, but at a cost. The big push should be toward reducing this cost to an economic figure and toward developing a large enough synthetic-oil industry to have a significant impact on the level of imports.

Significantly, almost on the same day that POWER was discussing this need with Leathers, West Germany's Chancellor, Helmut Schmidt was expounding the use of German coal as the first national priority for the 1980s. Coal, which presently accounts for 28% of the energy consumed in Germany, vs 18% in the US, is heavily subsidized by the government, and Schmidt says that this subsidy would rise to more than $3-billion a year. "We are doing this," says Schmidt, "because coal, although more expensive, is the only important source of energy that allows us to be independent of foreign decisions."

And Leathers agrees: "You've got to get started. You're better off laying out a big subsidy for energy and keeping the dollar strong and the balance of payments up."

Thinking energy balance

"All industry and government schemes should be considered in terms of the total energy balance—how much useful energy is consumed or produced at every stage in the cycle. This information is available and it's a shame to have people making policy decisions without looking into it—or without even understanding it. That's why I'm so damned upset with those gasahol nuts," says Leathers. He points out that it takes more than twice as many Btus from various fuels to produce gasahol, as there are useable Btus in the fuel.

He emphasizes that problems with total energy balance are not new. "Way back in the industrial revolution, counterproductive laws were passed by the British government because there was no understanding of total energy balance. For instance, when it was noted that forests were being depleted to build houses, a decree was passed that all houses should be built of bricks. But it took more wood in the form of fuel to make bricks than it would to build houses; so Britain lost her forests anyway."

With the same energy-balance ideas in mind, Leathers takes out time from running a modern petrochemical facility to consider the energy problems involved in such basic endeavors as agriculture. "What's the net energy involved in corn production?" he asks. Through a gasification process, both energy to operate harvesting machinery and fertilizer could be obtained from the stalks and husks (stover) left after the corn is reaped. Given a fixed number of acres, could the stover be used to obtain a net energy balance without additional fuel input?" he asks.

"Everything has an energy component that must be considered in the total balance," Leathers points out, explaining that there are two basic forms of energy: *transient*, as experienced in a combustion process, and *formative*, that energy needed to create a material or component from raw materials. Energy balances that consider both types uncover the flaws in many proposed "solutions" to the energy crisis.

"There's a lot of talk about hydrogen as a fuel," he asys, "but you can calculate that if the hydrogen were free at the source; you'd need all the energy it contains just to pump it to the users." Geothermal energy has the same problems. "If you had geothermal water at 400F, you'd only use it if no other power source was available. Usually this water is found in arid areas, where the only available heat sink would be an air-cooled condenser. With isobutane as the working fluid, you might be able to extract 13% of the Btus as useful energy—9% by the time it was electricity.

Solar energy is of such low quality that the formative energy capital needed to build a solar plant could not easily be amortized by the transient energy that the plant generates. Leathers considers that passive solar systems or, more realistically, buildings designed to take account of solar energy in the total energy cycle, are a more profitable way to go.

Algae cultivation is another alternative being considered at Dow. A research group investigated the cultivation of an algae species containing the largest amount of sugar and protein, with the idea of fermentation and alcohol production. Results of the investigation showed that algae could not be grown and harvested at a net energy surplus. Leathers says, however, that if the algae is available anyway, it could be gasified to produce energy. "I've now got them looking at blue-green algae. This algae grows so fast in parts of the South that you can almost walk on it. I want to see if you can cultivate and gasify it with a net energy gain."

"The same considerations apply to burning garbage. If you've got to collect and transport the stuff anyway, you can make a case for burning it as a fuel. But, if you count the Btu cost of making garbage, the balance is ridiculous. You know those plastic glasses you get with your drink on an airplane? Well, just as an example, you can calculate that it costs 50,000 Btus just to get one pound of these plastic glasses on the plane." ■

Want a cleaner oil-fired boiler? Just add water

If you still think that oil and water don't mix, think again. A growing number of industrial energy users now substitute emulsions—homogenized mixtures of heavy oil and water—for 100% heavy oil to fuel their boilers. Among the reported benefits of the changeover: reductions in burner excess-air requirements and slag accumulations, and concomitant increases in boiler efficiency.

One believer in emulsion firing is Ed Holden, an engineering consultant at General Foods Corp's Technical Center in Tarrytown, NY. For the past few years, Holden and other engineers have been studying the effects of burning oil/water emulsions in industrial boilers at General Foods plants and elsewhere. His conclusion: "From past experience, it appears that boilers burning emulsions can stay cleaner than those burning straight oil. That means less sootblowing and lower maintenance costs at the end of the year."

Where have all our engineering leaders gone?

Never before has energy decision-making demanded as much broad insight as it does today. It takes leadership to address all the tough issues—be they environmental, economic, legal, or social—that face industrial energy users in a world of increasing complexity.

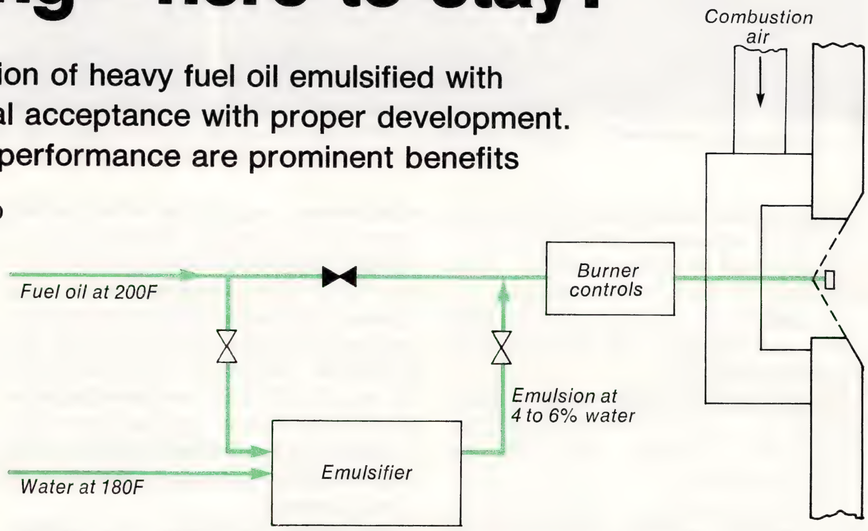
Engineering still determines the success or failure of any energy decision, however, so industry needs engineering leaders more today then ever. Their assignment is difficult: To find the optimum solutions to energy problems that may be obscured by nontechnical considerations. Will such a new breed of engineers arise and take charge, or will we suffer yet another shortage—that of innovative energy-systems planners? One man who has doubts about the current status of engineering leadership in American industry is Frank Feeley, an engineering consultant to Olin Corp's Chemicals Group.

"Leadership in engineering," claims Feeley, "has deteriorated in my working lifetime." His view is that today's graduates lack dedication to a career in engineering; instead, they aspire to more glamorous nontechnical positions. "To a

Emulsion firing—here to stay?

Recent studies in the combustion of heavy fuel oil emulsified with water could lead to commercial acceptance with proper development. Fuel savings and better boiler performance are prominent benefits

By E A Holden, General Foods Corp



1. Emulsifier system is installed in a cabinet near the burner front. Switch from straight oil firing to emulsion firing is actuated by pushbutton

In the area of combustion, attention has been directed recently to oil-burner developments using low excess air to improve burner performance. One method that has gained increasing popularity is the combustion of heavy fuel oil emulsified with water.

Research and development in emulsion firing has been largely prompted by university studies and US government-agency grants. In Europe, the French, the Russians, and the Danes are likewise engaged in emulsion studies and associated equipment development. The Canadian Combustion Research Laboratory in Ottawa is now testing a Canadian-built emulsifier.

With water emulsified in heavy fuel oil, research has shown that fuel-oil atomization is improved by the microexplosions of entrained water as the emulsion enters the combustion chamber. Finer atomization thus provides expectations of improved combustion with less carbon loss, less excess air, and perhaps better heat transfer.

Fuel-oil/water emulsification is a homogenization process. Some of the equipment is conventionally used to homogenize food products such as milk. Emulsifiers may be classified as: (1) positive displacement pumps that discharge the mixture against an impact ring, (2) centrifugal pumps that discharge the mixture through atomizing nozzles, and (3) high-frequency cavitation devices activated by a resonant generator. In principle, these devices apply *shear* to reduce water particle size and *cavitation* to achieve uniform distribution of water particles throughout the oil.

An emulsifier system is installed in a cabinet that is placed near the boiler front. Oil piping to and emulsion piping from the cabinet are shown in Fig. 1. A change from straight-oil firing to emulsion firing and vice versa is activated by a pushbutton mounted on the front of the cabinet, along with pertinent instruments and annunciator lights. When off-normal conditions occur, interlocks automatically revert flow from emulsified oil to straight oil.

The typical physical specifications for an emulsified heavy (No. 6) fuel oil are the following:

- Water particle size, 5 to 10 microns distributed uniformly throughout the oil.
- Water, 4-6% by volume.
- Water temperature, 180F.

The benefits claimed with emulsion firing include:

- *Improved combustion.* Microexplosions of emulsified water superatomizes the heavy fuel oil. The minute particles therefore undergo earlier ignition, as would be expected with lighter oil grades.
- *A shorter flame.* Combustion is completed with less residence time in the furnace.
- *Less excess air.* With finer atomization and a shorter flame, less air is required to reach and to envelop flame tailings.
- *Less carbon loss.* More complete burnout of carbon occurs due to superatomization and a shorter intense flame.
- *Improved boiler efficiency.* This is mainly due to reduced excess air and a cleaner boiler.

A benefit not usually mentioned is the probability that emulson firing may replace or supplement the use of fuel-oil additives. Various additives are touted as a means of improving combustion, of reducing slag accumulations, and of controlling boiler back-end and air-preheater corrosion. Fuel-additive benefits, therefore, parallel expectations from emulsion firing, especially the claim for improved combustion.

Slag reduction. For the case of a cleaner boiler, trials at one industrial plant over a period of several weeks with emulsion firing showed that heavy slag, which had developed during straight-oil firing, actually disappeared from the generating tubes. These trials were conducted with 17% emulsion. The dusty deposit that remained after a month's continuous service with emulsion firing was white/grey in color and measured 1/16-3/32 in. thick. Sootblowing was minimized,

Key operating conditions for straight and emulsified oils

Conditions	Straight oil	Emulsified oil
Excess air, %	20	20
Boiler exit-gas temp, F	500	500
Fuel-oil temp, F	200	200
Water temp, F	—	180
Emulsion water, %	—	5
Oil, Btu/lb	18,500	18,500
Emulsion, Btu/lb	—	17,575
Ambient-air temp, F	80	80

Coal: Mine it, don't undermine it

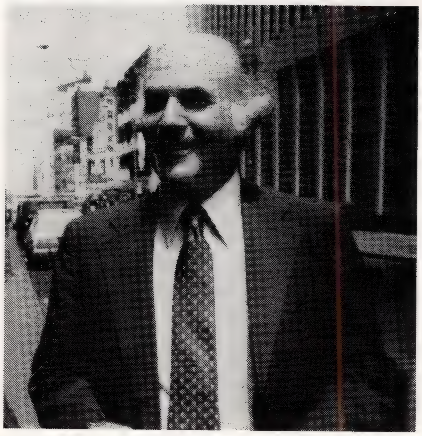
Federal policy now hinders industry's transition to coal. This consultant explains how, proposes changes, and offers advice to energy planners

The uncertain availability and cost of future energy sources are frustrating America's industrial decision-makers. Confused by contradictory national energy, environmental, and economic policies, large energy users are finding it harder to choose confidently among oil, gas, coal and waste as the fuel for generating power in future plants (box, below).

What's worse, that frustration and confusion may become an epidemic, according to Jerry Gambs, a vice-president at the New York City-based consulting engineering firm of Ford, Bacon & Davis Inc. He foresees more smaller industrial energy users facing the same tough choice because "individual plants must look more and more to standby power systems to protect at least some of their load."

By way of explanation, Gambs predicts that, "in the next 10-20 years, industry will face two serious shortages—a shortage of electric power from utilities and a shortage of petroleum products used to generate steam." Proven technology can help industry cope with both shortages, but only if Washington recognizes the dependence of America's economic future on a realistic national energy plan.

The utility shortfall, says Gambs, should begin to affect industry within the next two to four years on a regional basis. First to be hit will be those areas that depend heavily on nuclear power. Eyeing today's frequent shutdowns of operating nuclear reactors and delays in the licensing of new plants, Gambs expects that "more frequent brownouts



and blackouts in the 1980s will mean that industrial plants will have a difficult time operating as they've been used to, with sufficient electric power."

Add capacity—and use it

His solution: Install more diesel- or gas-turbine-based standby generating capacity in industrial plants. Those units, argues Gambs, need not sit idle, waiting for a power failure; they can be used in the interim for peak shaving if the plant's electric load varies over a 24-hr period. Gambs adds that such a scheme is already in operation at several plants in the US.

To cope with shortages of petroleum used to generate steam, Gambs recommends cogeneration because it kills two birds with one efficient stone. By passing the hot exhaust gas from a diesel engine or gas turbine through a heat-recovery boiler, a plant can meet its steam requirements "for free" while satisfying part of its electrical demands. And, by adding a steam turbine downstream of the boiler in a combined-cycle configuration, surplus electricity can be produced while extracting additional Btus from expensive fuel.

Unfortunately, today's diesels and gas turbines burn oil or gas, so Gambs further recommends that designers of new industrial plants consider coal-fired cogeneration "as a first alternative" where environmental standards allow it. He, and Ford, Bacon & Davis, are particularly high on atmospheric fluidized-bed boilers because "they are both high in efficiency and can satisfy emissions requirements for SO_2 and NO_x."

Coal is not a panacea, however. Gambs urges industrial energy planners to weigh several aspects of coal use before making any decisions. Compared to oil, coal certainly makes sense in terms of availability and price. "We already have a global shortage of oil, with demand exceeding supply by almost 2-million bbl/day, out of the free world's daily consumption of 51-million bbl," reports Gambs. He expects this situation to continue, and therefore sees oil prices continuing to skyrocket.

Obstacles facing coal

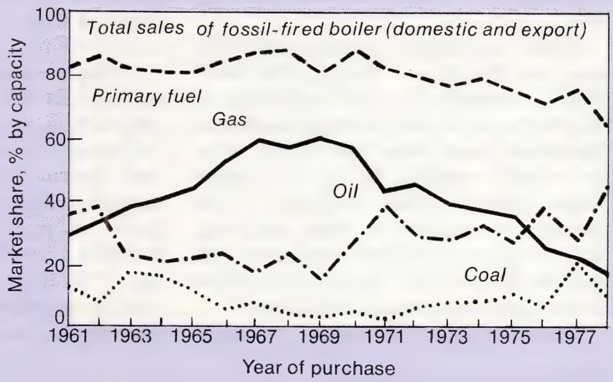
Coal, on the other hand, now is roughly one-third the price of oil, on a \$/million-Btu basis. As for the future, Gambs states, "I don't believe that the price of coal is going to track anywhere near the price of oil. It hasn't in the recent past, and in the future it probably will cost even a smaller percentage of the price of oil as crude escalates in price."

Despite favorable outlooks for coal

Boiler buyers high on waste, fickle on coal

Orders for fossil-fired steam generators have declined since 1970, when they accounted for 87.2% of all purchases (right). Area above the top curve represents the capacity of units ordered that are designed to burn waste fuels. Reasons for the decrease in sales of fossil-fired boilers include: (1) conflict between fuel-use and environmental laws, (2) general slowdown is the US economy, and (3) energy conservation in industrial process plants.

Orders for coal-fired boilers peaked at 19.8% in 1963, but then declined to a low of 1% in 1971, one year after passage of the Clean Air Act. Since then, market share has roller-coastered back to its traditional average of 9.4% last year.



price and availability, Gambs sees these three dark clouds on its horizon: (1) the huge capital investment required to build coal-fired plants, (2) environmental restrictions, and (3) an inadequate coal-transportation system.

Regarding cost, Gambs admits that "when you compare the cost of a coal-fired plant with that of an oil-fired one, the oil-fired unit probably is still a better economic bet, even at today's high oil prices. That's because a coal-fired plant costs anywhere from two to three times more than an oil-fired system of similar capacity."

But he adds, "when you're looking at a $50/bbl price for oil five years from now, coal may indeed provide lower-cost steam and electric power over the plant's lifetime." Besides, "what can we expect to have in the way of oil in 50, 40 or even 30 years?"

Gambs thinks that industry needs tax incentives to justify huge capital commitments to coal-fired plants. "Sure, burning coal lessens our dependence on foreign oil and that's good for the country. But how you interest anyone in that kind of investment when he won't see any return on it for 10 years? That doesn't have much appeal to the guy who has to make a decision today."

According to Gambs, "the best incentive for all these coal-utilization projects would be either a 100% depreciation in the first year, or a 50% tax credit—in short, a very large financial inducement to invest in a costly coal-fired plant." Existing and proposed tax incentives, he adds, just aren't sufficient to make new-plant planners hungry for coal. Nor are they adequate to encourage conversion of existing oil- and gas-fired industrial boilers to coal, a conclusion drawn by a federal-government study (see box, right).

What would be the effect of such coal-conversion incentives on our economy? Gambs replies, "the Treasury would lose some tax revenues. I don't know exactly how much, but I do know that nobody is really taking a hard enough look at the pros and cons of lost taxes versus the country's overall gain from reduced oil imports."

Coal vs the environment

Even if such incentives are made available, however, environmental regulations still inhibit any large-scale transition to coal. Gambs' terse suggestion: "Drastically modify the Clean Air Act." In some areas, he claims, it's virtually impossible to put in a new coal-fired plant and still comply with the act's nondegradation clauses. "We have to understand that if we continue to say that coal can't be burned, the result will be greater use of oil and gas. That will require increased imports—far beyond what anyone is willing to admit—and will have a disastrous impact on our economy."

The third problem facing greater use of coal is the present inadequacy of America's coal-transportation system. Gambs claims that, in some areas of the country, "it's impossible to deliver coal from the mine to customers."

Since President Carter proposed that the country double its use of coal, America's coal-transportation system has improved little, if at all. On a regional basis, production of western coal has increased substantially, so western railroads have put in additional lines. But eastern railroads, according to Gambs, "are probably in worse shape than they were three or four years ago."

Who is to pay for needed improvements? Gambs thinks that railroads should foot the bill, and recoup their investment by charging higher rates. That's not the way it's worked, however. In many cases, out of sheer necessity, industrial plants have had to pay for sidings to reach the main line. "And there are instances," says Gambs, "of coal companies owning fleets of hopper cars and locomotives, and of even maintaining repair shops to keep rolling stock available to move coal to customers."

Piping coal to customers

Another possibility that intrigues Gambs is greater use of pipelines to move slurries of coal and oil or of coal and water. He sees pipelines as a particularly viable option in the West, where long distances justify it, and where large users like utilities need upwards of 10-15-million tons of coal annually. Gambs explains that coal/water slurries burn perfectly well when injected directly into boilers with Cyclone burners. In fact, he adds, such a pipeline project was engineered and build by Ford, Bacon & Davis in the late 1950s to serve Cleveland Electric Illuminating Co.

Builders of long-distance pipelines need the right of eminent domain on a federal basis, however, and that's where Congress comes in. Since Washington is involved in all three areas that affect coal's future—economic incentives, environmental regulations, and upgrading of the coal-transportation system—Gambs feels that industrial leaders should spend more time there. "In particular, they should be discussing the implications of DOE and EPA regulations that often emerge contrary to the intent of laws that authorized them."

But what's really needed, he says, is direct industrial input to the legislative process. "Top management has a duty to tell their congressmen what impact specific bills will have on their plant and on their community. All too often, Washington operates in a vacuum." ■

Coal conversion makes sense at large plants

The Powerplant & Industrial Fuel Use Act of 1978 requires all but the smallest industrial plants to burn fuels other than oil and gas—coal and process wastes, for example—where feasible. But widespread conversion to coal and alternate fuels is not yet taking place in the industrial sector.

A recent study conducted by T D Anderson and E C Fox of the Oak Ridge National Laboratory (ORNL) identifies the important factors that restrict the acceptance of coal by industry. They include:

- Lack of substantial economic incentive to burn coal.
- Greater financial risk, caused by the higher capital requirements for coal-fired plants than for oil-and/or gas-fired ones.
- Lack of a clear environmental policy.

The ORNL study—summarized in TM-6661, "Conversion to coal in the industrial sector," which is available for $5.25 through the National Technical Information Service, US Dept of Commerce, 5285 Port Royal Rd, Springfield, Va 22161—investigates the cost of replacing existing oil- and/or gas-fired boilers with ones capable of burning coal. Recognize that the majority of oil- and/or gas-fired boilers are not capable of burning coal because of their relatively small furnaces, tight tube spacing, etc. Thus, the use of coal is not a simple matter of switching fuels; rather, new facilities must be constructed.

The economic feasibility of siting coal-fired boilers in seven major industrial areas was evaluated to account for regional variations in the costs of coal and transportation. For each area, the affordable cost of coal was calculated for three separate combustion systems and four plant sizes.

Specifically, these were (1) stoker- and pulverized-coal-fired boilers burning low-sulfur coal, (2) stoker- and pulverized-coal-fired boilers using high-sulfur coal and a flue-gas desulfurization system, and (3) atmospheric fluidized-bed boilers firing high-sulfur coal in plants of 100,000, 250,000, 500,000, and 1-million lb/hr.

Anderson and Fox drew two general conclusions from their work:

- The price that can be paid for coal increases with the size of the installation. Reason: Equipment and operating costs, per unit of output, are less for large plants.
- The cost of coal delivered to the plant decreases as plant output increases. Due to the economics of scale, large users pay less for coal and its transportation.

These findings confirm earlier studies that concluded that the larger the plant, the greater the incentive to switch from oil and/or gas to coal. But, the ORNL study reveals that, in general, a plant must produce more than 1-million lb/hr before economic incentives justify direct combustion of coal.

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Establishing cost/benefit and payback for a flue-gas analyzer in power plants

Reducing excess air and stack temperature in industrial boilers can lead to dramatic fuel savings. Key to documenting these savings is the flue-gas analyzer. Here's how to relate its cost to fuel saved

By Victor Black, Teledyne Analytical Instruments

In the operation of industrial boilers, it is never possible to achieve perfect combustion efficiency (see box, below). Trace amounts of combustibles are always present, even in the most efficient reaction processes. Other variants, including boiler type, design, and application, have a more direct impact on combustion efficiency.

The usual operating approach maintains excess air flow at a higher value than the stoichiometric value. As shown in the chart, both safety and maximum combustion efficiency exist in the relatively narrow band from 1% to 3% oxygen. Boilers with air leakage, however, may be impossible to trim to this level without a concurrent increase in flue-gas combustibles.

As fuel costs continue to rise, the economics involved with combustion assume a higher and higher priority, as does the analytical instrumentation designed to measure the two prime components of flue gas (oxygen and combustibles) that are the best indicators of combustion efficiency and safe operation. Likewise, it is certain that the demand of coal, mixed oils, solid wastes, wood derivatives, and more exotic fuels will increase as industry searches for economical and practical energy-producing alternatives.

Optimizing the air/fuel ratio. The best and most obvious approach toward achieving an economical solution to fuel costs is optimizing the air/fuel ratio, and thereby avoiding both incomplete combustion (too little oxygen) and heat losses due to too much oxygen. Too much oxygen also leads to such stochastic problems as increased metal corrosion, air pollution, increased power to operate fans, and, of course, higher fuel costs.

An idea of fuel costs can be obtained by examining a typical electric-utility boiler complex, such as Southern California Edison Co's steam-generating plant at Etiwanda, Calif. The plant is used to generate a portion of the electric power for Los Angeles. It incorporates four top-fired boilers, each consuming 12,000 bbl/day of low-sulfur Indonesian oil. At current prices, this represents a daily expenditure of approximately $1-million—for fuel costs alone at the steam plant. Obviously, any percentage savings in fuel achieved through improved combustion efficiency would represent cost savings of such magnitude as to make the expense for analysis instrumentation dwindle to insignificance.

Calculating cost/benefit, payback. In the table, combustion efficiency for natural gas is determined when the amount of combustibles in the flue gas is negligible. Under this assumption, efficiency is a function of the percentage of oxygen in the dry flue-gas products and the flue-gas temperature for a given fuel—in this case, natural gas. The computations involved in establishing cost/benefit and payback are straightforward:

Step 1. Measure the stack temperature at the same location from which the flue-gas sample is to be drawn (presumably from the "last-pass" section of the boiler).

Step 2. Take the oxygen and combustibles percentage readings.

Step 3. Using the tabulation whose stack temperature is closest to that measure, note the efficiency percentage reading that coincides with the percentage oxygen reading taken in *Step 2.* For purposes of constructing a model, assume that a 7%-oxygen reading was taken at a stack temperature of 350F. Efficiency would be noted as 79.09%.

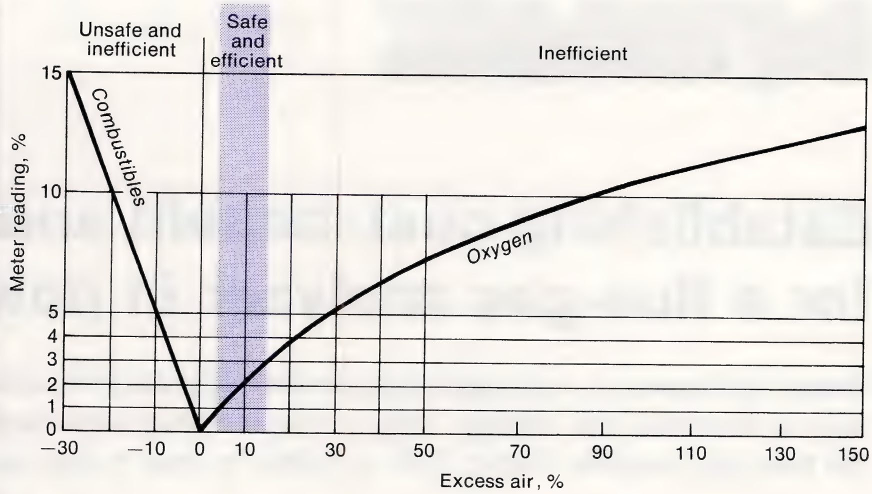
Step 4. Adjust the air damper to decrease the oxygen percentage. The oxygen reading, however, must be stable and exclude combustibles. An unstable reading at or below 2% oxygen could drop below 0% oxygen and create a potential explosive situation. A higher than desired oxygen reading that persists after air damping, or a consistently unstable oxygen reading, could indicate an open furnace port, a malfunctioning damper, or excessive air leakage into the boiler. Combustibles should register below 0.1% for safe and efficient operation. Generally, combustion levels exceeding 2% are potentially very explosive.

Step 5. After adjustment, allow a few

Reviewing fuel-burning fundamentals

When burning fossil fuels in a boiler, an exact amount of oxygen is required for complete and efficient combustion. (The stoichiometric value is a theoretical point at which all oxygen and combustibles are converted to CO_2, H_2O, heat, etc.) If too little oxygen is supplied, part of the fuel will remain unburned and be lost with the flue gases, creating waste, pollution, and a possible explosive hazard. Too much oxygen will lower the efficiency of the process by conducting heat away and carrying it out the stack as waste.

As a general rule, each reduction of 1% of flue-gas oxygen content is equivalent to about 1% savings in fuel. Combustibles in the flue-gas stream will affect the chemical equilibrium, as well as influence the kinetics of the reaction, rates of diffusion, and mixing efficiencies. When combustibles are present, more air (or oxygen) is needed to complete the reaction. The addition of air will, of course, result in a higher stack temperature and reduced efficiency.



Safety and maximum combustion efficiency exist in a relatively narrow band

minutes for the stack temperature to drop, then take another stack temperature reading. Let us assume that the second temperature reading is 300F and the oxygen reading is 2%. Efficiency is then noted as 81.74%.

Step 6. Compute the fuel savings (FS) with the following equation:

FS = [(Improved eff − Original eff) ÷ Improved eff] × Original fuel cost

Step 7. Fuel cost for the example cited, before adjusting, was roughly $3800/month. With an original combustion efficiency of 79.09% and an improved combustion efficiency of 81.74%, the fuel savings is:

FS = [(81.74 − 79.09) ÷ 81.74] × 3800 = $123.20/month

Step 8. With the fuel savings established, we can now find the payback period by dividing the cost of the analyzer (a quality instrument will cost about $1800) by the fuel savings:

Payback = Analyzer cost ÷ Fuel savings = $1800 ÷ $123.20/month = 14.6 months

In this case, the analyzer will pay for itself in about a year and three months. This payback computation, however, does not include additional cost savings resulting from such benefits as longer boiler life, reduced overall maintenance, and a lesser need for pollution-control equipment.

It is obvious from the fuel costs in the example that the boiler profiled was quite small. For this analysis, a portable flue-gas analyzer was used. It is battery-powered and incorporates integral pumps and a sample extraction and conditioning system. Moreover, the analyzer registers the percentage concentration of both oxygen and combustibles in the flue-gas stream on direct meter readouts, making it an effective instrument in a cost/benefit and payback study. ■

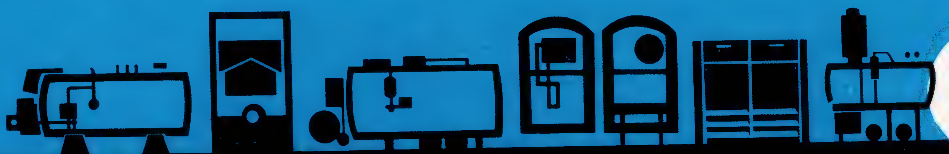
Combustion efficiency for gas various stack temperatures[1]

Excess air, %	Excess oxygen, %	Efficiency, % 250F	300F	350F	400F	450F	500F	550F
0.00	0.00	83.06	82.09	81.11	80.12	79.12	78.11	77.10
4.48	1.00	82.93	81.93	80.91	79.88	78.85	77.80	76.74
9.44	2.00	82.79	81.74	80.69	79.62	78.54	77.45	76.35
14.94	3.00	82.64	81.54	80.44	79.32	78.20	77.06	75.92
21.09	4.00	82.46	81.32	80.16	79.00	77.82	76.63	75.43
28.02	5.00	82.26	81.06	79.85	78.63	77.39	76.15	74.89
35.86	6.00	82.04	80.77	79.50	78.21	76.91	75.59	74.27
44.82	7.00	81.79	80.44	79.09	77.73	76.35	74.96	73.56
55.16	8.00	81.49	80.07	78.63	77.18	75.71	74.24	72.75
67.23	9.00	81.15	79.62	78.09	76.53	74.97	73.39	71.80
81.48	10.00	80.74	79.10	77.44	75.77	74.09	72.39	70.67
98.58	11.00	80.26	78.47	76.67	74.86	73.03	71.19	69.32
119.48	12.00	79.66	77.71	75.73	73.75	71.74	69.72	67.68
145.60	13.00	78.92	76.75	74.56	72.35	70.13	67.88	65.62
179.18	14.00	77.96	75.51	73.05	70.56	68.05	65.52	62.97
223.93	15.00	76.69	73.87	71.03	68.17	65.29	62.38	59.44

[1]Tables are also available for the following fuels: Nos. 2 and 6 fuel oil, subbituminous coal, propane, bagasse, and wood chips (0, 8, 17, and 50% moisture, respectively). Stack temperatures range from 250 to 1000F in 25F increments

QUESTION:

How to save energy and cut fuel costs



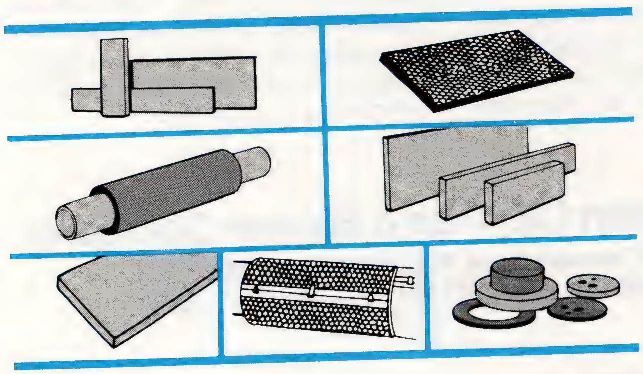
ANSWER:

Simple...INSULATE all power systems components

In all the hassle about the energy problem, two facts seem certain: one, *the energy crisis will get worse before it gets better;* second, *fuel costs will continue to rise substantially.*

How to cope with this frustrating situation? One sure-fire solution is to insulate all power systems components including especially:

Superheated steam lines	Furnace duct work
Heat exchangers	Heaters
Kilns	Tanks
Ovens	Process vessels
Towers	Stills
Piping	Furnaces
Reformers	Heated mixers
Boilers	Condensers
Reactors	Kettles



Eagle-Picher offers a comprehensive line of mineral and ceramic fiber insulating materials for use on heated processing equipment operating at temperatures as high as 2300 F. The complete product line includes block, board, felt and blanket insulations, and pipe insulations. Eagle-Picher also produces custom-shaped insulations to original equipment manufacturers' specifications. Efficient, economical, fuel-saving Thermal Insulation . . . you name it, Eagle-Picher makes it and delivers it promptly!

Need insulation for your fuel economy program? We'll get you completely covered for maximum money-savings. Write or phone today for product data sheets.

EAGLE EP PICHER

EAGLE-PICHER INDUSTRIES, INC.
Fibers Department
580 Walnut Street, Cincinnati, OH 45202
Phone: (513) 721-7010
Associate Member National
Insulation Contractors Association

CIRCLE 99 ON READER SERVICE CARD

A century of growth hasn't changed our sense of values.

"Good goods, and never-ceasing efforts to make them better".

That was the motto proclaimed back in 1879 by the founders of Garden City Fan Company. And it isn't easy to improve on an idea like that. For us, it still stands.

Back then we were known for movement and distribution of ambient air in buildings such as the new Chicago Post Office and Customs House, the Kansas City Convention Hall (at the turn of the century the largest such structure in the nation), the Denver Public Library Building, and the monumental Chicago Coliseum, along with a great variety of industrial and commercial air movement installations.

The technology of fan and blower design and application, as every other science, has advanced dramatically since then. The emphasis of our business has shifted to a specialization on handling superheated and highly corrosive and abrasive air, the high-volume and pressure requirements for environmental control systems and other difficult air in complex industrial processes.

But one thing remains essentially the same: we still try today to give our customers a better product and better service, and to do a little bit more than we might really have to. Which is what we were saying a century ago.

Garden City Fan & Blower Company

1749 Terminal Road, Niles, Michigan 49120
Telephone: (616) 683-1150

amca MEMBER

CIRCLE 100 ON READER SERVICE CARD

CODES & STANDARDS

Getting involved in lawmaking

Engineers are well aware of the negative effects some recent energy and environmental legislation is having on industrial growth. Help counter the trend to greater government control of industry by sharing your technical expertise with elected officials and their staffs

Just about everyone in industry is familiar with the nation's energy problems. As an engineer, you sense something is wrong. You know, for instance, that:

- The US has enough coal to satisfy its energy needs for hundreds of years, yet an energy crisis prevails and coal production is increasing only marginally on an annual basis.
- Nuclear fuel can generate electricity at relatively low cost and with relatively little impact on the environment, compared to other fuels, yet orders for new central stations are rare and construction delays and cancellations are common.

The reason for this situation, a few experts contend, is that several laws passed recently by congress prevent industry from curing its, and the country's ills.

Some new environmental statutes, for example, have enabled small pressure groups, whose views do not necessarily reflect those of the majority of Americans, curtail important industrial projects.

You also may remember that voters in at least seven states have defeated, by a 2 to 1 margin, legislation that would have banned nuclear power plants. Despite the defeat at the polls, antinuclear groups continue to delay nuclear development by court action. In some cases, the delays have been so long that projects have been cancelled because they are no longer economically attractive.

In the coal fields, the Natural Resources Defense Council (NRDC) recently used environmental laws as the basis for a successful suit against the Dept of Interior. Result of the litigation is that Interior must expand its already prepared environmental impact statement (EIS) on coal leasing. This action effectively freezes any new leases on federal lands until lengthy new EIS requirements are fulfilled, and that's not expected until 1981. (Details on this and other energy/environment litigation of interest to engineers are covered by Dr H Peter Metzger, manager of public-affairs planning for Public Service Co of Colorado, in his paper *The coercive utopians: Their hidden agenda.* Copies of the paper are available from Metzger.)

How does all this add up? The answer should be obvious: If you and other professionals in industry do not get involved in the federal lawmaking process, the energy situation may get worse before it gets better. As a private citizen you can do little to counter the decisions of federal regulators, who, for the most part, are appointed rather than elected.

However, you can provide valuable input to senators and representatives, and their staffs, which may help to shape future laws more favorably and restrict the power of regulatory personnel. The closing of a few loopholes in any piece of legislation can go a long way in minimizing legal action against needed power plants. Remember that your thoughts, and those of your coworkers, often mean more to elected officials than your company's views, because your company doesn't vote.

Getting to know lawmakers

Perhaps the first step in becoming more active in the law-making process is to identify the senators from your state and the representative from your district. If you already know who they are, and have the addresses and telephone numbers of their home offices, check to see if any of the congressmen you help elect are members of committees with jurisdiction over energy and environmental legislation (see list, next page).

Remember that congressional committees wield a great deal of power, because without the approval of the committee given the responsibility to review a particular piece of legislation, that bill probably will not reach the floor of the House or Senate for a vote. Sometimes it is easier to influence the content of a particular bill when it is in committee, where a limited number of lawmakers are present, than when the entire Congress is involved.

Next, familiarize yourself with the voting record of your senators and representative to see what posture they normally take on energy and environmental matters. The table at the end of the article presents some of this information. But it obviously does not reflect the thinking of freshmen congressmen. You can follow their voting on important issues in publications such as the *Congressional Quarterly*. These periodi-

cals, which are available in most libraries—public and company—also can keep you current on bills recently introduced in the Congress.

When you have completed this basic research you are ready to contact your elected officials. Writing letters is one way of getting your views across and of thanking your congressmen for taking a particular stand on issues important to you. Your letters will be read, and usually will be answered, and your views considered.

In preparing a letter, keep these points in mind:

- Make your letter as complete and as technically correct as possible.
- Come right to the point; make your letter as short as possible. The most effective letters are one page or less—and have wide margins. Figure that if it takes you more than about 10 minutes to draft a letter it probably has too much detail and this causes it to lose impact.
- State your position clearly and give supporting and convincing reasons for it. Reinforce your position with facts and figures.
- Keep a friendly tone.
- Write your letter in a manner that permits you to send copies of it to others—such as members of committees and subcommittees handling the particular bill (especially the committee chairman), the bill's sponsors, etc.

Personal contact often is more effective than a letter. You can call your representative's secretary in Washington (table, right) or in his home district for an appointment. The latter is recommended. At home, schedules usually allow more time for meetings with constituents and your suggestions can be given greater consideration. Some things to remember before you visit:

- Keep the discussion simple and get right to the point. Elected officials generally have limited knowledge on scientific and engineering subjects. In the last Congress, for example, only five senators and representatives had technical backgrounds.
- Do not try to cover too many topics at one meeting; people often become sidetracked when several subjects are discussed at one time.
- Come prepared with voting records. Ask questions. Find out why your congressman voted the way he did on certain bills.
- Follow up your visit with a letter which briefly summarizes your main points and thank your congressman for his time.

Phone, wires effective, too

Telephone calls are effective, too, particularly a day or two before a vote on bill of interest to you is scheduled. You can call the congressman either in Washington or in his local office. An aide will record your message. Note that westerners can make calls to Washington very cheaply if they call before 8 a.m. local time.

Finally, do not neglect wires. Rates are $2 for a 15-word public-opinion message and $2.75 for a 100-word mailgram. Simply dial Western Union toll-free at 800/257-2241 (from New Jersey, dial 800/632-2271) and tell the operator the name of the congressman the message goes to. The charge for the wire will be added to your monthly telephone bill.

Compiled by Marcia Vanterpool

Here's how to contact your congressman

By telephone:
Call the Capitol switchboard, 202/224-3121, or his home office

By mail or telegram:
The Honorable *John Doe*
House of Representatives
Washington, DC 20515
Dear Mr. (Ms.) *Doe:*

The Honorable *John Doe*
United States Senate
Washington, DC 20510
Dear Senator *Doe:*

Know members of key Senate and House committees

Knowing the members of key Senate and House committees with jurisdiction over energy and environmental matters (see tabulation below) is extremely important. Bear in mind that, without approval of the committee given the responsibility to review a particular piece of legislation, that bill probably will not reach the floor of the House or Senate for a vote.

Typically, legislation introduced in the House and/or Senate is referred to a committee for review. The committee, in turn, passes it to a specialized subcommittee for study, hearings (you can participate in them as an interested party), revisions, and approval. Note that the jurisdiction and names of subcommittees may change from session to session, so you should contact the subcommittee chairman's office to identify current responsibilities.

After subcommittee action, the bill goes back to the full committee where further hearings may be held and revisions made. Finally, the full committee may approve the bill and recommend that the chamber it serves pass the proposal. A bill rarely is given an unfavorable report. Instead, no action is taken, thereby killing it.

After a bill is approved by the full House or Senate (it may be amended on the floor before passage), it is sent to the other house for consideration. There it goes through a similar review process. Bills that survive both houses (often a House/Senate conference committee must be convened to work out the final details of the legislation) are sent to the President for his signature. If he decides to veto the legislation, a two-thirds majority of both houses is needed to override the veto and make the bill law.

SENATE

Commerce, Science & Transportation

Jurisdiction of the Commerce, Science & Transportation Committee (202/224-5115) includes science, engineering, technology, and research and development policy. Members of the committee are listed below:

Howard Cannon (Nev), Chairman	Howell Heflin (Ala)
Warren Magnuson (Wash)	Bob Packwood (Ore)
Russell Long (La)	Barry Goldwater (Ariz)
Ernest Hollings (SC)	Harrison Schmitt (NM)
Daniel Inouye (Hawaii)	John Danforth (Mo)
Adlai Stevenson (Ill)	Nancy Kassebaum (Kans)
Wendell Ford (Ky)	Larry Pressler (SD)
Donald Riegle, Jr (Mich)	John Warner (Va)
J James Exon (Neb)	

Energy & Natural Resources

Jurisdiction of the Energy & Natural Resources Committee (202/224-4971) includes energy policy, regulation, conservation, research and development; solar and nuclear energy; oil, gas, and coal production and distribution; mining; hydroelectric power. Subcommittees of particular interest to power engineers and their chairmen are these:

Energy Research & Development—Frank Church
Energy Regulation—Bennet Johnston
Energy Conservation & Supply—John Durkin
Energy Resources & Materials Production—Wendell Ford

Members of the main committee are listed below:

Henry Jackson (Wash), Chairman	Paul Tsongas (Mass)
Frank Church (Idaho)	Bill Bradley (NJ)
J Bennet Johnston (La)	Mark Hatfield (Ore)
Dale Bumpers (Ark)	James McClure (Idaho)
Wendell Ford (Ky)	Lowell Weicker, Jr (Conn)
John Durkin (NH)	Pete Domenici (NM)
Howard Metzenbaum (Ohio)	Ted Stevens (Alaska)
Spark Matsunaga (Hawaii)	Henry Bellmon (Okla)
John Melcher (Mont)	Malcolm Wallop (Wyo)

Environment & Public Works

Jurisdiction of the Environment & Public Works Committee (202/224-6176) includes environmental policy, research and development; ocean dumping; solid-waste disposal and recycling; water resources; water, air, and noise pollution; environmental regulation; control of nuclear energy. Subcommittees of particular interest to power engineers and their chairmen are these:

Environmental Pollution —Edmund Muskie

Water Resources—Mike Gravel

Nuclear Regulation—Gary Hart

Members of the main committee are listed below:

Jennings Randolph (W Va), Chairman
Edmund Muskie (Me)
Mike Gravel (Alaska)
Lloyd Bentsen (Tex)
Quentin Burdick (ND)
John Culver (Iowa)
Gary Hart (Colo)
Daniel Moynihan (NY)
Robert Stafford (Vt)
Howard Baker, Jr (Tenn)
Pete Domenici (NM)
John Chafee (RI)
Alan Simpson (Wyo)
Larry Pressler (SD)

HOUSE

Government Operations

Jurisdiction of the Government Operations Committee (202/225-5051) includes the budget and overall economy and efficiency of government operation at all levels. The subcommittee of particular interest to power engineers and its chairman is:

Environment, Energy & Natural Resources (202/225-6427)—Anthony Toby Moffett

Members of the main committee are listed below:

Jack Brooks (Tex), Chairman
L H Fountain (NC)
Dante Fascell (Fla)
William Moorhead (Pa)
Fernand St Germain (RI)
Don Fuqua (Fla)
John Conyers, Jr (Mich)
Cardiss Collins (Ill)
John Burton (Calif)
Richardson Preyer (NC)
Robert Drinan (Mass)
Glenn English (Okla)
Elliot Levitas (Ga)
David Evans (Ind)
Anthony Toby Moffett (Conn)
Andrew Maguire (NJ)
Les Aspin (Wis)
Henry Waxman (Calif)
Floyd Fithian (Ind)
Benjamin Rosenthal (NY)
Peter Kostmayer (Pa)
Ted Weiss (NY)
Michael Synar (Okla)
Robert Matsui (Calif)
Eugene Atkinson (Pa)
Frank Horton (NY)
John Erlenborn (Ill)
John Wydler (NY)
Clarence Brown (Ohio)
Paul McCloskey, Jr (Calif)
Thomas Kindness (Ohio)
Robert Walker (Pa)
Arlan Stangeland (Minn)
M Caldwell Butler (Va)
Lyle Williams (Ohio)
Jim Jeffries (Kans)
Olympia Snowe (Me)
Wayne Grisham (Calif)
H Joel Deckard (Ind)

Interior & Insular Affairs

Jurisdiction of the Interior & Insular Affairs Committee (202/225-2761) includes mineral-land laws and claims; mining; petroleum conservation; regulation, research, and development of the domestic nuclear-energy industry. Subcommittees of particular interest to power engineers and their chairmen are these:

Energy & the Environment (202/225-8331)—Morris Udall

Mines & Mining (202/225-1661)—Jim Santini

Water & Power Resources (202/225-6042)—Abraham Kazen

Members of the main committee are listed below:

Morris Udall (Ariz), Chairman
Phillip Burton (Calif)
Robert Kastenmeier (Wis)
Abraham Kazen, Jr (Tex)
Jonathan Bingham (NY)
John Seiberling (Ohio)
Harold Runnels (NM)
Antonio Borja Won Pat (Guam)
Bob Eckhardt (Tex)
Jim Santini (Nev)
James Weaver (Ore)
Bob Carr (Mich)
George Miller (Calif)
James Florio (NJ)
Dawson Mathis (Ga)
Philip Sharp (Ind)
Edward Markey (Mass)
Peter Kostmayer (Pa)
Baltasar Corrada (PR)
Austin Murphy (Pa)
Nick Ranhall II (W Va)
Bruce Vento (Minn)
Jerry Huckaby (La)
Lamar Gudger (NC)
James Howard (NJ)
Jerry Patterson (Calif)
Ray Kogovsek (Colo)
Pat Williams (Mont)
Don Clausen (Calif)
Manuel Lujan, Jr (NM)
Keith Sebelius (Kans)
Don Young (Alaska)
Steven Symms (Idaho)
James Johnson (Colo)
Robert Lagomarsino (Calif)
Dan Marriott (Utah)
Ron Marlenee (Mont)
Mickey Edwards (Okla)
Richard Cheney (Wyo)
Charles Pashayan, Jr (Calif)
Robert Whittaker (Kans)
Douglas Bereuter (Neb)
Melvin Evans (VI)

Interstate & Foreign Commerce

Jurisdiction of the Interstate & Foreign Commerce Committee (202/225-2927) includes regulation of interstate transmission of power, oil compacts, natural gas, and water projects. The subcommittee of particular interest to power engineers and its chairman is:

Energy & Power (202/225-1030)—John Dingell

Members of the main committee are listed below:

Harley Staggers (W Va), Chairman
John Dingell (Mich)
Lionel Van Deerlin (Calif)
John Murphy (NY)
David Satterfield III (Va)
Bob Eckhardt (Tex)
Richardson Preyer (NC)
James Scheuer (NY)
Richard Ottinger (NY)
Henry Waxman (Calif)
Timothy Wirth (Colo)
Philip Sharp (Ind)
James Florio (NJ)
Anthony Toby Moffett (Conn)
Jim Santini (Nev)
Andrew Maguire (NJ)
Marty Russo (Ill)
Edward Markey (Mass)
Thomas Luken (Ohio)
Doug Walgren (Pa)
Albert Gore, Jr (Tenn)
Barbara Mikulski (Md)
Ronald Mottl (Ohio)
Phil Gramm (Tex)
Al Swift (Wash)
Mickey Leland (Tex)
Richard Shelby (Ala)
Samuel Devine (Ohio)
James Broyhill (NC)
Tim Lee Carter (Ky)
Clarence Brown (Ohio)
James Collins (Tex)
Norman Lent (NY)
Edward Madigan (Ill)
Carlos Moorhead (Calif)
Matthew Rinaldo (NJ)
Dave Stockman (Mich)
Marc Marks (Pa)
Tom Corcoran (Ill)
Gary Lee (NY)
Tom Loeffler (Tex)
William Dannemeyer (Calif)

Public Works & Transportation

Jurisdiction of the Public Works & Transportation Committee (202/225-4472) includes water power and pollution of navigational waters. Members of the committee are listed below:

Harold Johnson (Calif), Chairman
Ray Roberts (Tex)
James Howard (NJ)
Glenn Anderson (Calif)
Robert Roe (NJ)
Mike McCormack (Wash)
John Breaux (La)
Norman Mineta (Calif)
Elliott Levitas (Ga)
James Oberstar (Minn)
Jerome Ambro (NY)
Henry Nowak (NY)
Robert Edgar (Pa)
Marilyn Lloyd (Tenn)
John Fary (Ill)
W G Hefner (NC)
Robert Young (Mo)
David Bonior (Mich)
Allen Ertel (Pa)
Billy Lee Evans (Ga)
Ronnie Flippo (Ala)
Nick Rahall II (W Va)
Douglas Applegate (Ohio)
Bill Royer (Calif)
Geraldine Ferraro (NY)
Brian Donnelly (Mass)
Earl Hutto (Fla)
Eugene Atkinson (Pa)
Donald Albosta (Mich)
Marvin Leath (Tex)
William Boner (Tenn)
William Harsha (Ohio)
James Cleveland (NH)
Don Clausen (Calif)
Gene Snyder (Ky)
John Hammerschmidt (Ark)
Bud Shuster (Pa)
James Abdnor (SD)
Gene Taylor (Mo)
Barry Goldwater, Jr (Calif)
Tom Hagedorn (Minn)
Arlan Stangeland (Minn)
Bob Livingston (La)
Newt Gingrich (Ga)
William Clinger, Jr (Pa)
Gerald Solomon (NY)
Jerry Lewis (Calif)

Science & Technology

Jurisdiction of the Science & Technology Committee (202/225-6371) includes environmental, scientific, and energy (except nuclear) research and development. Subcommittees of particular interest to power engineers and their chairmen are these:

Energy Research & Production (202/225-5743)—Mike McCormack

Energy Development & Application (202/225-4296)—Richard Ottinger

Natural Resource & Environment (202/225-1066)—J Ambro

Science, Research & Technology (202/225-8844)—George Brown

Members of the main committee are listed below:

Don Fuqua (Fla), Chairman
Robert Roe (NJ)
Mike McCormack (Wash)
George Brown, Jr (Calif)
James Scheuer (NY)
Richard Ottinger (NY)
Tom Harkin (Iowa)
Jim Lloyd (Calif)
Jerome Ambro (NY)
Marilyn Lloyd (Tenn)
James Blanchard (Mich)
Doug Walgren (Pa)
Ronnie Flippo (Ala)
Dan Glickman (Kans)
Albert Gore, Jr (Tenn)
Wes Watkins (Okla)
Robert Young (Mo)
Richard White (Tex)
Harold Volkmer (Mo)
Donald Pease (Ohio)
Howard Wolpe (Mich)
Nicholas Mavroules (Mass)
Bill Nelson (Fla)
Beryl Anthony, Jr (Ark)
Stanley Lundine (NY)
Allen Ertel (Pa)
Kent Hance (Tex)
John Wydler (NY)
Larry Winn, Jr (Kans)
Barry Goldwater, Jr (Calif)
Hamilton Fish, Jr (NY)
Manuel Lujan, Jr (NM)
Harold Hollenbeck (NJ)
Robert Dornan (Calif)
Robert Walker (Pa)
Edwin Forsyth (NJ)
Ken Kramer (Colo)
William Carney (NY)
Robert Davis (Mich)
Toby Roth (Wis)
Don Ritter (Pa)

Voting record of congressmen reveals their posture on energy, environmental matters

Senators and congressmen	Voting record: Clean Water Act[1]	Clean air[2]	Surface mining[3]
Alabama			
Heflin, Howell (D)	N	N	N
Stewart, Donald (D)	N	N	N
Bevill, Tom (D)	+		–
Buchanan, John (R)	+	+	–
Dickinson, William (R)		+	–
Edwards, Jack (R)	+	+	–
Flippo, Ronnie (D)	+		–
Nichols, Bill (D)	+	+	+
Shelby, Richard (D)	N	N	N
Alaska			
Gravel, Mike (D)	+	+	+
Stevens, Ted (R)	+	+	
Young, Don (R)	+		
Arizona			
DeConcini, Dennis (D)	+	+	
Goldwater, Barry (R)	+		–
Rhodes, John (R)		+	–
Rudd, Eldon (R)	+	+	–
Stump, Bob (D)	+	–	–
Udall, Morris (D)		+	+
Arkansas			
Bumpers, Dale (D)	+		+
Pryor, David (D)	N	N	N
Alexander, Bill (D)	+	+	–
Anthony, Beryl, Jr (D)	N	N	N
Bethune, Ed (R)	N	N	N
Hammerschmidt, John Paul (R)	+	–	
California			
Cranston, Alan (D)	+	+	
Hayakawa, S I (R)	+	–	
Anderson, Glenn (D)	+	+	+
Badham, Robert (R)	+		
Beilenson, Anthony (D)	–		+
Brown, George, Jr (D)	+	+	+
Burgener, Clair (R)	+	+	+
Burton, John (D)	–	–	+
Burton, Phillip (D)	–		+
Clausen, Don (R)	+	+	–
Coelho, Tony (D)	N	N	N
Corman, James (D)	+	+	+
Danielson, George (D)	+	+	+
Dannemeyer, William (R)	N	N	N
Dellums, Ronald (D)	–		+
Dixon, Julian (D)	N	N	N
Dornan, Robert (R)	+	+	–
Edwards, Don (D)	–	–	+
Fazio, Vic (D)	N	N	N
Goldwater, Barry, Jr (R)	+	+	+
Grisham, Wayne (R)	N	N	N
Hawkins, Augustus (D)	+	+	+
Johnson, Harold (D)	+	+	–
Lagomarsino, Robert (R)	+	+	+
Lewis, Jerry (R)	N	N	N
Lloyd, Jim (D)	+	+	+
Lungren, Dan (R)	N	N	N
Matsui, Robert (D)	N	N	N
McCloskey, Paul, Jr (R)	–	–	+
Miller, George (D)	–	–	+
Mineta, Norman (D)	+	–	+
Moorhead, Carlos (R)	+	+	
Panetta, Leon (D)	+	+	+
Pashayan, Charles, Jr (R)	N	N	N
Patterson, Jerry (D)	+	+	
Rousselot, John (R)	+	–	
Roybal, Edward (D)	+	–	+
Royer, Bill (R)	N	N	N
Shumway, Norman (R)	N	N	N
Stark, Fortney (D)	–	–	
Thomas, William (R)	N	N	N
Van Deerlin, Lionel (D)	+	+	+
Waxman, Henry (D)	–	–	
Wilson, Bob (R)	+	+	+
Wilson, Charles (D)	+	+	
Colorado			
Armstrong, William (R)	+		
Hart, Gary (D)	+	+	+
Johnson, James (R)	+	+	–
Kogovsek, Ray (R)	N	N	N
Kramer, Ken (R)	N	N	N
Schroeder, Patricia (D)	–	+	+
Wirth, Timothy (D)	–	–	+
Connecticut			
Ribicoff, Abraham (D)	+		+
Weicker, Lowell, Jr (R)	+		+
Cotter, William (D)	+	+	
Dodd, Christopher (D)	+	+	
Giaimo, Robert (D)	+	+	+
McKinney, Stewart (R)	+	+	–
Moffett, Anthony (D)	–	–	+
Ratchford, William (D)	N	N	N
Delaware			
Biden, Joseph, Jr (D)	+	+	+
Roth, William (R)	+	+	+
Evans, Thomas (R)	+		–
Florida			
Chiles, Lawton (D)	+	+	+
Stone, Richard (D)	+	+	+
Bafalis, L A (R)	+		
Bennett, Charles (D)	+	+	+
Chappell, Bill, Jr (D)	+	+	
Fascell, Dante (D)	+	+	+
Fuqua, Don (D)	+		
Gibbons, Sam (D)	+	–	+
Hutto, Earl Dewitt (D)	N	N	N
Ireland, Andy (D)	+	+	
Kelly, Richard (R)	+	+	–
Lehman, William (D)	–	+	+
Mica, Dan (D)	N	N	N
Nelson, Bill (D)	N	N	N
Pepper, Claude (D)		+	+
Stack, Edward (D)	N	N	N
Young, C. W. (R)		+	–
Georgia			
Nunn, Sam (D)	+		+
Talmadge, Herman (D)	+		–
Barnard, Doug (D)	+	+	
Brinkley, Jack (D)	+	+	
Evans, Billy Lee (D)	+	+	
Fowler, Wyche, Jr (D)		+	+
Gingrich, Newt (R)	N	N	N
Ginn, Bo (D)	+		–
Jenkins, Ed (D)	+	+	–
Levitas, Elliott (D)	+	+	+
Mathis, Dawson (D)	+		
McDonald, Larry (D)	+	–	–
Hawaii			
Inouye, Daniel (D)	+	+	
Matsunaga, Spark (D)	+	+	–
Akaka, Daniel (D)	+	+	+
Heftel, Cecil (D)		+	
Idaho			
Church, Frank (D)	+	+	+
McClure, James (R)	+	+	–
Hansen, George (R)	+	–	–
Symms, Steve (R)	+	–	–
Illinois			
Percy, Charles (R)			+
Stevenson, Adlai (D)	+	+	+
Anderson, John (R)	+	+	+
Annunzio, Frank (D)		+	–
Collins, Cardiss (D)	+	+	
Corcoran, Tom (R)	+	+	–
Crane, Daniel (R)	N	N	N
Crane, Philip (R)	+	+	
Derwinski, Edward (R)	+	+	–
Erlenborn, John (R)	+	+	–
Fary, John (D)	+	+	–
Findley, Paul (R)	+		–
Hyde, Henry (R)	+	+	–
Madigan, Edward (R)	+	+	+
McClory, Robert (R)	+	+	–
Michel, Robert (R)	+	+	–
Mikva, Abner (D)	–	–	+
Murphy, Morgan (D)	+	+	
O'Brien, George (R)	+		–
Price, Melvin (D)	+		
Railsback, Tom (R)		+	
Rostenkowski, Dan (D)		+	+
Russo, Marty (D)	–	+	+
Simon, Paul (D)		+	+
Stewart, Bennet (D)	N	N	N
Yates, Sidney (D)	+	–	+
Indiana			
Bayh, Birch (D)	+	+	+
Lugar, Richard (R)	+	+	–
Benjamin, Adam, Jr (D)	+	+	+
Brademas, John (D)	+	+	+
Deckard, H Joel (R)	N	N	N
Evans, David (D)	+	+	
Fithian, Floyd (D)	+	+	
Hamilton, Lee (D)	+		+
Hillis, Elwood (R)	+	+	–
Jacobs, Andrew, Jr (D)	+	+	+
Myers, John (R)	+	+	–
Quayle, Dan (R)	+		
Sharp, Philip (D)	+	+	+
Iowa			
Culver, John (D)	+	+	+
Jepsen, Roger (R)	N	N	N
Bedell, Berkley (D)	+	+	+
Grassley, Charles (R)	+	+	–
Harkin, Tom (D)	+	+	
Leach, Jim (R)	+	+	–
Smith, Neal (D)	+	+	–
Tauke, Thomas (R)	N	N	N
Kansas			
Dole, Robert (R)	+	+	
Kassebaum, Nancy (R)	N	N	N
Glickman, Dan (D)	+		+
Jeffries, Jim (R)	N	N	N
Sebelius, Keith (R)	+	+	
Whittaker, Robert (R)	N	N	N
Winn, Larry, Jr (R)	+	+	–
Kentucky			
Ford, Wendell (D)	+	+	–
Huddleston, Walter (D)	+	+	–
Carter, Tim Lee (R)	+	+	–
Hopkins, Larry (R)	N	N	N
Hubbard, Carroll, Jr (D)	+	+	–
Mazzoli, Romano (D)	+	+	
Natcher, William (D)	+	+	–

Senators and congressmen	Clean Water Act[1]	Clean air[2]	Surface mining[3]
Perkins, Carl (D)	+	+	+
Snyder, Gene (R)	+	+	
Louisiana			
Johnston, Bennett (D)	+		
Long, Russell (D)	+		–
Boggs, Lindy (D)	+	+	
Breaux, John (D)	+	+	
Huckaby, Jerry (D)	+	+	–
Leach, Claude (D)	N	N	N
Livingston, Bob (R)			
Long, Gillis (D)	+		–
Moore, W Henson (R)	+	–	–
Treen, David (R)	+	+	–
Maine			
Cohen, William (R)	+	+	+
Muskie, Edmund (D)	+	+	
Emery, David (R)	+	+	+
Snowe, Olympia (R)	N	N	N
Maryland			
Mathias, Charles (R)	+	+	+
Sarbanes, Paul (D)	+	+	+
Barnes, Michael (D)	N	N	N
Bauman, Robert (R)	+	+	–
Byron, Beverly (D)	N	N	N
Holt, Marjorie (R)	+	+	–
Long, Clarence (D)	+	+	+
Mikulski, Barbara (D)	+	+	+
Mitchell, Parren (D)	+	+	+
Spellman, Gladys Noon (D)	+	+	+
Massachusetts			
Kennedy, Edward (D)	+	+	+
Tsongas, Paul (D)		+	+
Boland, Edward (D)	+	+	
Conte, Silvio (R)	+	+	+
Donnelly, Brian (D)	N	N	N
Drinan, Robert (D)		+	+
Early, Joseph (D)	+	+	
Heckler, Margaret (R)	+	+	+
Markey, Edward (D)	+	+	+
Mavroules, Nicholas (D)	N	N	N
Moakley, Joe (D)	+	+	
O'Neill, Thomas, Jr (D)			
Shannon, James (D)	N	N	N
Studds, Gerry (D)	–	+	+
Michigan			
Levin, Carl (D)	N	N	N
Riegle, Donald (D)	+	+	
Albosta, Donald (D)	N	N	N
Blanchard, James (D)	+	+	+
Bonior, David (D)	+	+	+
Brodhead, William (D)	–	+	+
Broomfield, William (R)	+	+	+
Carr, Bob (D)	+	+	+
Conyers, John, Jr (D)		–	+
Davis, Robert (R)	N	N	N
Diggs, Charles, Jr (D)		+	+
Dingell, John (D)	–	+	+
Ford, William (D)	+	+	
Kildee, Dale (D)	+	+	+
Nedzi, Lucien (D)	+	+	+
Pursell, Carl (R)	+	+	+
Sawyer, Harold (R)	+		
Stockman, Dave (R)	+	+	
Traxler, Bob (D)	+	+	+
Vander Jagt, Guy (R)	+	+	+
Wolpe, Howard (D)	N	N	N
Minnesota			
Boschwitz, Rudy (R)	N	N	N
Durenberger, David (R)	N	N	N
Erdahl, Arlen (R)	N	N	N
Frenzel, Bill (R)	+	+	
Hagedorn, Tom (R)	+	+	+
Nolan, Richard (D)	–	–	+
Oberstar, James (D)	+	+	+
Sabo, Martin Olav (D)	N	N	N
Stangeland, Arlan (R)	+		–
Vento, Bruce (D)	+	+	+
Mississippi			
Cochran, Thad (R)	+	+	–
Stennis, John (D)	+	+	–
Bowen, David (D)	+	+	–
Hinson, Jon (R)	N	N	N
Lott, Trent (R)	+	+	–
Montgomery, G V (D)	+	+	
Whitten, Jamie (D)	+	+	–
Missouri			
Danforth, John (R)	+	+	–
Eagleton, Thomas (D)	+	+	
Bolling, Richard (D)	+	+	+
Burlison, Bill (D)	+	+	–
Clay, William (D)		+	
Coleman, E Thomas (R)	+		+
Gephardt, Richard (D)	+	+	+
Ichord, Richard (D)	+	+	
Skelton, Ike (D)	+	+	+
Taylor, Gene (R)	+	+	
Volkmer, Harold (D)	+	+	
Young, Robert (D)	+	+	+
Montana			
Baucus, Max (D)	+	+	+
Melcher, John (D)	+	+	–
Marlenee, Ron (R)	+	+	–
Williams, Pat (D)	N	N	N
Nebraska			
Exon, James (D)	N	N	N
Zorinsky, Edward (D)	+	+	+
Bereuter, Douglas (R)	N	N	N
Cavanaugh, John (D)	+	–	
Smith, Virginia (R)	+	+	–
Nevada			
Cannon, Howard (D)	+	+	–
Laxalt, Paul (R)	+	+	–
Santini, Jim (D)	+	+	–
New Hampshire			
Durkin, John (D)	+	–	
Humphrey, Gordon (R)	N	N	N
Cleveland, James (R)	+	+	
D'Amours, Norman (D)	+	+	–
New Jersey			
Bradley, Bill (D)	N	N	N
Williams, Harrison, Jr (D)	+	+	+
Courter, James (R)	N	N	N
Fenwick, Millicent (R)	+	–	+
Florio, James (D)	+		
Forsythe, Edwin (R)	+		
Guarini, Frank (D)	N	N	N
Hollenbeck, Harold (R)	+	+	+
Howard, James (D)	+	+	+
Hughes, William (D)	+	+	+
Maguire, Andrew (D)	–	–	+
Minish, Joseph (D)	+	+	–
Patten, Edward (D)	+	+	–
Rinaldo, Matthew (R)	+	+	+
Rodino, Peter, Jr (D)	+	+	+
Roe, Robert (D)	+		
Thompson, Frank, Jr (D)	+	+	+
New Mexico			
Domenici, Pete (R)	+	+	–
Schmitt, Harrison (R)	+	+	–
Lujan, Manuel, Jr (R)	+	+	
Runnels, Harold (D)	+		–
New York			
Javits, Jacob (R)	+	+	+
Moynihan, Daniel Patrick (D)	+	+	+
Addabbo, Joseph (D)	+	+	
Ambro, Jerome (D)	+	+	+
Biaggi, Mario (D)	+	+	
Bingham, Jonathan (D)	–	–	+
Carney, William (R)	N	N	N
Chisholm, Shirley (D)	+	+	
Conable, Barber, Jr (R)	+		–
Downey, Thomas (D)	+	+	
Ferraro, Geraldine (D)	N	N	N
Fish, Hamilton, Jr (R)	–	+	
Garcia, Robert (D)			
Gilman, Benjamin (R)	+	+	
Green, S William (R)	N	N	N
Hanley, James (D)	+	+	+
Holtzman, Elizabeth (D)	–	–	+
Horton, Frank (R)	+	+	
Kemp, Jack (R)	+	+	–
LaFalce, John (D)	+	+	–
Lee, Gary (R)	N	N	N
Lent, Norman (R)	+	+	
Lundine, Stanley (D)	+	+	+
McEwen, Robert (R)	+		
McHugh, Matthew (D)	+	+	+
Mitchell, Donald (R)	+		+
Murphy, John (D)	+	+	
Nowak, Henry (D)	+	+	+
Ottinger, Richard (D)	–		+
Peyser, Peter (D)	N	N	N
Rangel, Charles (D)		+	
Richmond, Frederick (D)	–	–	+
Rosenthal, Benjamin (D)	–	–	+
Scheuer, James (D)	–	–	+
Solarz, Stephen (D)	–	–	+
Solomon, Gerald (R)	N	N	N
Stratton, Samuel (D)	+	+	
Weiss, Ted (D)	–	–	+
Wolff, Lester (D)	+	–	+
Wydler, John (R)	+	+	
Zeferetti, Leo (D)	+		
North Carolina			
Helms, Jesse (R)	+	–	–
Morgan, Robert (D)	+		+
Andrews, Ike (D)	+	+	–
Broyhill, James (R)	+	+	–
Fountain, L H (D)	+	+	–
Gudger, Lamar (D)	+	+	–
Hefner, W G (D)	+	+	
Jones, Walter (D)	+	+	–
Martin, James (R)	+	+	–
Neal, Stephen (D)	+	+	+
Preyer, Richardson (D)	+	+	
Rose, Charles (D)	+	+	
Whitley, Charles (D)	+	+	–
North Dakota			
Burdick, Quentin (D)	+	+	–
Young, Milton (R)	+	+	–
Andrews, Mark (R)	+	+	–
Ohio			
Glenn, John (D)	+	+	–
Metzenbaum, Howard (D)	+	+	–
Applegate, Douglas (D)	+	+	+
Ashbrook, John (R)	+	–	–
Ashley, Thomas (D)	+	+	
Brown, Clarence (R)	+	+	–
Devine, Samuel (R)	+	+	–
Gradison, Willis, Jr (R)	+	+	
Guyer, Tennyson (R)	+	+	–
Hall, Tony (D)	N	N	N
Harsha, William (R)	+	+	
Kindness, Thomas (R)	+	+	–
Latta, Delbert (R)	+		
Luken, Thomas (D)	+	+	+
Miller, Clarence (R)	+	+	+
Mottl, Ronald (D)	–	+	+

Senators and congressmen	Clean Water Act[1]	Clean air[2]	Surface mining[3]
	Voting record		
Oakar, Mary Rose (D)	+	+	+
Pease, Donald (D)	+	+	+
Regula, Ralph (R)	+	+	−
Seiberling, John (D)	−	+	+
Stanton, J William (R)	+		−
Stokes, Louis (D)	+	+	+
Vanik, Charles (D)	−		+
Williams, Lyle (R)	N	N	N
Wylie, Chalmers (R)	−	+	+
Oklahoma			
Bellmon, Henry (R)	+	+	−
Boren, David (D)	N	N	N
Edwards, Mickey (R)	+	+	−
English, Glenn (D)	+	+	−
Jones, James (D)		+	−
Steed, Tom (D)	+	+	
Synar, Michael Lynn (D)	N	N	N
Watkins, Wes (D)	+		−
Oregon			
Hatfield, Mark (R)	+		
Packwood, Bob (R)	+	+	+
AuCoin, Les (D)	+	+	
Duncan, Robert (D)	+	+	−
Ullman, Al (D)	+		+
Weaver, James (D)	+		+
Pennsylvania			
Heinz, H John, III (R)	+	+	−
Schweiker, Richard (R)	+	+	−
Atkinson, Eugene (D)	N	N	N
Bailey, Don (D)	N	N	N
Clinger, William, Jr (R)	N	N	N
Coughlin, Lawrence (R)	−	+	+
Dougherty, Charles (R)	N	N	N
Edgar, Robert (D)	−	−	+
Ertel, Allen (D)	+	+	+
Flood, Daniel (D)	+	+	−
Gaydos, Joseph (D)	+	+	−
Goodling, William (R)	+	+	−
Gray, William, III (D)	N	N	N
Kostmayer, Peter (D)	−	−	+
Lederer, Raymond (D)	+	+	−
Marks, Marc (R)	+	+	−
McDade, Joseph (R)	+	+	+
Moorhead, William (D)		+	−
Murphy, Austin (D)	+	+	−
Murtha, John (D)	+	+	−
Myers, Michael (D)	+	+	−
Ritter, Don (R)	N	N	N
Schulze, Richard (R)	+	+	−
Shuster, Bud (R)	+	+	−
Walgren, Doug (D)		+	
Walker, Robert (R)	+		−
Yatron, Gus (D)	+	+	−
Rhode Island			
Chafee, John (R)			+
Pell, Claiborne (D)	+	+	
Beard, Edward (D)	+	+	+
St. Germain, Fernand (D)	+	+	
South Carolina			
Hollings, Ernest (D)	+	+	−
Thurmond, Strom (R)	+	+	−
Campbell, Carroll, Jr (R)	N	N	N
Davis, Mendel (D)	+	+	
Derrick, Butler (D)	+	+	
Holland, Ken (D)	+		
Jenrette, John, Jr (D)	+	+	−
Spence, Floyd (R)	+		−
South Dakota			
McGovern, George (D)	+		
Pressler, Larry (R)	+		+
Abdnor, James (R)	+		
Daschle, Thomas (D)	N	N	N

Senators and congressmen	Clean Water Act[1]	Clean air[2]	Surface mining[3]
	Voting record		
Tennessee			
Baker, Howard (R)	+	+	−
Sasser, Jim (D)	+	+	
Beard, Robin (R)	+	+	
Boner, William Hill (D)	N	N	N
Duncan, John (R)	+	+	−
Ford, Harold (D)	+	+	−
Gore, Albert, Jr (D)	+	+	+
Jones, Ed (D)	+	+	
Lloyd, Marilyn Bouquard (D)	+	+	−
Quillen, James (R)	+	+	−
Texas			
Bentsen, Lloyd (D)	+	+	−
Tower, John (R)	+		
Archer, Bill (R)	+	+	−
Brooks, Jack (D)	+		
Collins, James (R)	+	−	−
de la Garza, E (D)	+	+	−
Eckhardt, Bob (D)	−	+	+
Frost, Martin (D)	N	N	N
Gonzalez, Henry (D)	+	−	+
Gramm, Phil (D)	N	N	N
Hall, Sam, Jr (D)	+	+	−
Hance, Kent (D)	N	N	N
Hightower, Jack (D)	+	+	+
Kazen, Abraham, Jr (D)	+	−	+
Leath, Marvin (D)	N	N	N
Leland, Mickey (D)	N	N	N
Loeffler, Tom (R)	N	N	N
Mattox, Jim (D)	+	+	+
Paul, Ron (R)	N	N	N
Pickle, J J (D)	+	+	
Roberts, Ray (D)	+	+	
Stenholm, Charles (D)	N	N	N
White, Richard (D)	+	+	−
Wilson, Charles (D)	+	+	+
Wright, Jim (D)	+	+	
Wyatt, Joe, Jr (D)	N	N	N
Utah			
Garn, Jake (R)	+	−	−
Hatch, Orrin (R)	+	−	−
Marriott, Dan (R)	+	+	−
McKay, Gunn (D)	+	+	
Vermont			
Leahy, Patrick (D)	+		+
Stafford, Robert (R)	+	+	+
Jeffords, James (R)		−	+
Virginia			
Byrd, Harry, Jr (D)	+	+	−
Warner, John (R)	N	N	N
Butler, M Caldwell (R)	+	+	−
Daniel, Dan (D)	+	+	−
Daniel, Robert, Jr (R)	+	+	−
Fisher, Joseph (D)	+	+	+
Harris, Herbert, II (D)	+	+	+
Robinson, J Kenneth (R)	+	+	−
Satterfield, David, III (D)	+	−	−
Trible, Paul, Jr (R)	+	+	−
Wampler, William (R)		+	−
Whitehurst, G William (R)	+		
Washington			
Jackson, Henry (D)	+	+	−
Magnuson, Warren (D)	+	+	−
Bonker, Don (D)	+	+	
Dicks, Norman (D)	+	+	−
Foley, Thomas (D)	+	+	−
Lowry, Michael (D)	N	N	N
McCormack, Mike (D)	+	+	−
Pritchard, Joel (R)	+	+	
Swift, Al (D)	N	N	N
West Virginia			
Byrd, Robert (D)	+	+	−
Randolph, Jennings (D)	+	+	−

Senators and congressmen	Clean Water Act[1]	Clean air[2]	Surface mining[3]
	Voting record		
Mollohan, Robert (D)	+	+	+
Rahall, Nick Joe, II (D)	+	+	+
Slack, John (D)	+	+	+
Staggers, Harley (D)		+	+
Wisconsin			
Nelson, Gaylord (D)	+	+	+
Proxmire, William (D)	+	+	+
Aspin, Les (D)		+	
Baldus, Alvin (D)	+	+	+
Kastenmeier, Robert (D)	−	+	+
Obey, David (D)	+	+	+
Petri, Thomas (R)	N	N	N
Reuss, Henry (D)	+	+	+
Roth, Toby (R)	N	N	N
Sensenbrenner, James, Jr (R)	N	N	N
Zablocki, Clement (D)	+	+	−
Wyoming			
Simpson, Alan (R)	N	N	N
Wallop, Malcolm (R)	+		−
Cheney, Richard (R)	N	N	N

FOOTNOTES

N-New member of Congress.

[1] The Clean Water Act Amendments of 1977 (PL 95-217) passed Congress with a majority vote in 1977, a revision and extension of the 1972 Federal Water Pollution Control Act (PL 92-500). Major provisions include: authorization of fund for construction grants for municipal sewage treatment plants, increased powers for the states to certify construction grants, and restrictions on the Corps of Engineers' authority to issue dredge-and-fill permits for waters and wetlands. The recorded vote is shown in the table above (a + indicates a vote for passage of the bill).

[2] The Clean Air Act Amendments of 1977 (PL95-95) passed both houses of Congress Aug 4, 1977 when the conference report was adopted by voice votes. The recorded vote on the original House version of the bill (HR6161) is presented in the table above (a + indicates that the congressman was in favor of the bill). It did not differ substantially in content from the final bill with respect to rules governing design and operation of electric-utility power plants.

[3] Passage of the Surface Mining Control & Reclamation Act (PL95-87) on July 21, 1977 culminated a five-year effort to impose federal regulations on strip-mining activities. Coal companies lobbied hard against many provisions of the bill as it originally was proposed and in some cases were successful—particularly in the Senate, where, observers say, there was little desire for a strong law. As finally approved by both houses of Congress, however, the law reportedly made most mining-company officials unhappy; by contrast, it pleased environmentalists for the most part.

The vote on one House amendment to the original bill, as recorded in the table, gives you some insight as to which side of the energy/environmental fence members of Congress are on. That amendment would have restricted mining on western alluvial valley floors—defined as the arid and semiarid areas of the west where the floors of valleys formed by streams offer the best available land and water supplies for farming and ranching—west of the 100th meridian only if permits were issued before Jan 4, 1977, or if mines were in commercial production one year before the bill was enacted. A vote for the restriction of mining on alluvial valley floors is identified in the table by +.

The conference committee which worked out the final details of the law, softened this amendment by permitting mining of the valley floors if it did "not interrupt, discontinue, or preclude farming." Thus mining is permissible on undeveloped rangelands or on small farmlands if it would have a negligible impact on agricultural production.

Know key energy, environmental laws

Legislation recently enacted by Congress bears heavily on the siting, design, construction, and operation of industrial powerhouses. Here's what you should know before making binding commitments

By **James E Levin, PE,** and **Douglas L Hazelwood,** A T Kearney Inc

During the 1970s, a substantial number of laws have been enacted by the federal government to help protect the environment. Within the past few years, significant energy legislation has also begun to flow from Washington. These laws have resulted in the promulgation of many regulations with which industry must now comply.

More regulations are now being developed by EPA and DOE in response to specific provisions of the latest laws pertaining to air, water, solid waste, and energy. These laws are of great interest and are expected to have a profound impact on industry.

The main purposes of this article are: (1) to review the key environmental and energy laws that affect industrial powerhouses; (2) to describe the regulations pursuant to those laws already on the books as well as those in developmental stages; and (3) to indicate how the laws and the regulations affect industry.

The specific laws covered herein are these:

- The Resource Conservation & Recovery Act (RCRA).
- The Clean Air Act.
- The Clean Water Act.
- The Fuel Use Act.
- The Energy Mobilization Board legislation.

How RCRA, especially Subtitle C, affects industrial powerhouses

RCRA was enacted in 1976. Unlike most environmental laws, RCRA received little fanfare on its passage, perhaps because its enactment followed closely on the heels of the Toxic Substances Control Act, which attracted hefty publicity and industry attention.

Nonetheless, RCRA is one of the most important environmental laws yet passed, and one that will affect many segments of industry. The law covers the management of solid wastes generated by industry, including residue and sludge byproducts from air- and water-pollution control equipment, and ash collected from combustion processes. The combination of RCRA, the Clean Water Act, and the Clean Air Act gives to the federal government through EPA, the power to regulate and monitor all industrial residues, wastes, and discharge streams.

The scope of Subtitle C

Subtitle C of RCRA is of greatest interest to industry at present because it empowers EPA to identify and regulate hazardous wastes. EPA recently estimated that 10 to 20% of all industrial wastes (but excluding mining and agricultural wastes) will be classified as hazardous under the definitions being proposed, and therefore will be subject to new hazardous-waste regulations, which will control the generation, storage, transportation, and disposal of such wastes.

Within Subtitle C, Section 3001 requires EPA to promulgate regulations identifying and listing hazardous wastes. EPA published proposed Section 3001 regulations in the Federal Register on Dec 18, 1978, along with proposed regulations for waste generators (Section 3002) and for storage, treatment, and disposal (Section 3004). After reviewing comments on these proposed regulations by industry and other interested parties, EPA expects to promulgate final regulations by Jan 25, 1980. The regulations will take effect six months after promulgation.

In the proposed regulations, a waste is considered hazardous if it exhibits certain characteristics, or if it is included in a specific EPA listing of hazardous wastes. The characteristics inherent in a hazardous waste are ignitability, reactivity, corrosiveness, and toxicity.

Ignitability. A waste is considered hazardous as a result of ignitability if, in a liquid state, it has a flash point less than 140F, if it is a special type of compressed gas, or if it is an oxidizer.

Reactivity. A reactive waste is defined as normally unstable and capable of readily undergoing violent chemical change. This type of waste reacts violently with water, forms potentially explosive mixtures with water, or generates toxic fumes when mixed with water. It may be a cyanide- or sulfide-bearing waste that might generate toxic fumes under mildly acidic or basic conditions. By EPA defi-

Identify initialed terms

ANPR Advance notice of proposed rulemaking.
BACT Best available control technology.
BAT Best available treatment.
BCT Best conventional treatment.
BMP Best management practices.
DOE Department of Energy.
EMB Energy Mobilization Board.
EPA Environmental Protection Agency.
ERA Economic Regulatory Agency.
ESECA The Energy Supply & Environmental Coordination Act.
FERC Federal Energy Regulatory Commission.
FUA The Powerplant & Industrial Fuel Use Act.
LAER Lowest achievable emission rate.
MFBI Major fuel-burning installation.
NA Nonattainment.
NAAQS National ambient air-quality standards.
NESHAPS National emission standards for hazardous air pollutants.
NPDES National pollutant discharge elimination system.
NRDC National Resources Defense Council.
NSPS New source performance standards.
POTW Publicly owned treatment works.
PSD Prevention of significant deterioration.
RCRA The Resource Conservation and Recovery Act.
SIP State implementation plan.
TEP Toxicant extraction procedure.

Table 1: Comparison of EPA drinking-water standards and toxicant extracts

Toxicant	Drinking water standard, mg/liter	Maximum extract concentration, mg/liter
Arsenic	0.05	0.50
Barium	1.0	10.0
Cadium	0.010	0.10
Chromium	0.05	0.50
Lead	0.05	0.50
Mercury	0.002	0.02
Selenium	0.010	0.10
Silver	0.050	0.50
Endrin	0.0002	0.002
Lindane	0.0040	0.040
Methoxychlor	0.10	1.0
Toxaphene	0.0050	0.050
2, 4-D	0.10	1.0
2, 4, 5-TP	0.010	0.10

Source: *Federal Register*, Dec 18, 1978.

nition, a reactive waste is capable of detonation or of explosive decomposition or reaction at normal temperatures and pressures.

Corrosiveness. A waste is considered hazardous due to corrosiveness if it is aqueous and has a pH of 3 or less, or 12 or more. If a waste has a corrosion rate of more than 0.250 in./yr on SAE 1030 steel at a test temperature of 130F, it is also considered hazardous under RCRA.

Toxicity. A solid waste is considered hazardous due to toxicity if the extract obtained from applying a defined toxicant extraction procedure (TEP) to a waste sample has a concentration of any substance equal to or greater than ten times those established by EPA's Primary Drinking Water Standard (Table 1).

Section 3002, 3004 of RCRA

Section 3002 consists of regulations for recordkeeping, use of appropriate containers, labeling of containers, furnishing information on waste (mainly quantities), and disposition and submission of reports to EPA or any authorized state agency. A manifest system is proposed to ensure that wastes intended for off-site disposal are delivered to a treatment, storage, and disposal facility having a federal or state permit.

The proposed 3002 regulations only apply to plants generating more than 220 lb/month of hazardous waste. Those plants that generate less would be exempt from recordkeeping and manifest requirements as long as their wastes are stored, treated, and disposed of in acceptable facilities.

Regulations were also proposed for the treatment, storage, and disposal of hazardous wastes under Section 3004. They would require that hazardous waste landfills be lined with clay, plastic, or other materials to prevent wastes from leaching through the soil and into ground water.

Operators of hazardous-waste facilities would have to monitor their processes constantly, and site owners would have to monitor and maintain closed sites for 20 years to ensure that hazardous wastes do not leak from the site into the environment. EPA estimates that the three proposed hazardous-waste regulations will affect about 35-million ton/yr of waste.

What about combustion wastes?

Will the proposed regulations affect industrial powerhouses? EPA has created a "special waste" category for flue-gas desulfurization wastes, bottom ash, and flyash from fossil-fueled utilities. The final Subtitle C regulations are likely to broaden the scope of the special-waste category to include industrial powerhouse wastes as well. Under the proposed regulations, combustion process wastes have been exempted from most of the 3004 standards (especially the requirement to use secured landfills) because of several factors, including large generation rates, relatively low hazard levels, lack of information on the composition and characteristics of the wastes, unique characteristics of the generator, lack of data on the effectiveness of current or potential waste-management technologies for these wastes, and the technical and economic

Table 2: Amount of trace elements in selected high-volatile, bituminous coal ash

	Amount of trace element, mg/liter		
	Maximum	Minimum	Average[1]
Ag	3	1	[2]
B	2800	90	770
Ba	4660	210	1253
Be	60	4	17
Co	305	12	64
Cr	315	74	193
Cu	770	30	293
Ga	98	17	40
Ge	285	20	[2]
La	270	29	111
Mn	700	31	170
Ni	610	45	154
Pb	1500	32	183
Sc	78	7	32
Sn	825	10	171
Sr	9600	170	1987
V	840	60	249
Y	285	29	102
Yb	15	3	10
Zn	1200	50	310
Zr	1450	115	411

Source: "Characterization of ash from coal fueled power plants," EPA-600/7-77-010, January 1977.

[1] The number of samples used to compute average values was 24 for all trace elements except Sn (22) and Zn (14).

[2] Insufficient figures to compute an average value.

Table 3: Proposed requirements for powerhouse wastes

CFR code	Brief description of requirement
250.43 (f) (h)	Obtain a detailed chemical and physical analysis of each hazardous waste handled at the facility. Periodically sample the waste and analyze it for physical appearance, specific gravity, pH, and vapor pressure (if applicable). In the case of off-site disposal facilities, sample each truckload or shipment.
250.43-1	For new sources, do not locate facilities on active fault zones, in areas prone to flooding, in wetlands, in areas likely to jeopardize endangered species, or in a recharge zone of a sole-source aquifer. Also, active portions of the facility should be located at least 200 ft from the facility's property line.
250.43-2	A facility should be completely fenced in, gated, and have prominent warning signs.
250.43-5 (a), (b) (1), (6) (2) (i), (b) (6-7), and (c)	An owner or operator of a facility should use the manifest system described in the regulations, and should keep an operating log which describes the types and quantities of wastes handled along with the handling and disposition of these wastes. Manifests should be kept for three years. Fires, explosions, or releases of hazardous materials to the environment must be retained in the records.
250.43-6	The owner or operator is responsible for daily visual inspection of the facility.
250.43-7 (k), (l), and (m)	After a final closure of the site, the owner or operator must certify that the facility has been closed in accordance with federal (proposed) regulations. A survey plat must be provided. Also, the owner of a landfill where hazardous waste has not been removed as part of closure shall provide post-closure care for at least 20 years after closure.
250.43-8 (a), (c), and (d)	A groundwater monitoring system should be installed at the facility, consisting of at least four monitoring wells to collect leachate. Each well should be periodically sampled, analyses made, and appropriate records kept.

practicability of improving the 3004 standards for facilities managing such wastes. Those standards that have been proposed to apply to combustion-process wastes are briefly described in Table 3.

Until recently, however, little has been known about any toxic characteristics of solid wastes from combustion processes or about the environmental adequacy of present disposal methods. Some studies have already been completed on trace-metal concentrations in coal ash. One EPA study found sufficient concentrations of trace elements in various types of coals to raise questions about the hazard potential of ash sources. Table 2 provides a small portion of the data presented in the EPA report, covering ash from high-volatile bituminous coals. It cannot be estimated from these data to what extent any of the trace elements will leach out if EPA's TEP is followed.

Included in the special-waste category are other large-volume solid wastes, such as mining wastes, cement-kiln dust, oil and gas drilling muds and brines, and phosphate-processing wastes. Because several industries have requested that their waste streams also be classified as special wastes, EPA is likely to include detailed eligibility criteria for qualifying as a special waste or applying for such classification in the final RCRA regulations, to be issued early next year.

In the meantime, EPA's Office of Solid Waste is initiating detailed studies for most, if not all, of the existing special wastes, to identify adequate treatment, storage, and disposal techniques. These studies are expected to be completed within two to three years. Coal-fired process wastes already have been studied, and a report has been prepared by an EPA contractor. It concludes that the majority of these solid wastes are nonhazardous, based on technical information currently available.

This would mean that most powerhouse solid wastes could be disposed of in sanitary landfills, and further, that mixtures of flyash, bottom ash, and scrubber sludge can be stabilized to improve structural strength and reduce permeability.

The Clean Air Act amendments of 1970 and 1977

The Clean Air Act, as amended, is intended to attain and maintain air quality sufficient to protect public health and welfare. The Act itself provides EPA with power to adopt and enforce air-pollution-control regulations. Under the 1970 amendments, EPA has promulgated national primary (health) and secondary (welfare) air-quality standards.

Standards have been set thus far to limit the maximum allowable ambient concentrations for carbon monoxide, nitrogen oxides, sulfur dioxide, photochemical oxidants, hydrocarbons, lead, and total suspended particulate matter.

State implementation plans

The Clean Air Act amendments of 1970 required EPA to adopt and enforce air-pollution-control regulations. EPA has issued air-quality standards and has required the states to develop state implementation plans (SIPs), indicating how EPA ambient air-quality standards will be met and enforced. Typically, each SIP is a compilation of state air-pollution-control regulations and strategies. A SIP will include emission limitations for existing stationary sources, land use controls, and transportation controls.

By July 1, 1975, each state was required to submit a SIP to EPA ensuring that air-quality standards would be met. EPA is required to review and approve the SIPs, making sure that they are in conformance with EPA criteria for attaining ambient air-quality standards. Each SIP is approved on an individual basis, giving the states flexibility to construct their programs and to consider variations in climate, geography, demography, and other special conditions for existing facilities. SIPs complement federal programs to regulate air quality for new and expanded facilities as well as hazardous air pollutants.

In August 1977, President Carter signed into law the 1977 amendments to the Clean Air Act (Public Law 95-95), culminating three years of legislative effort. These amendments allowed extensions to certain compliance deadlines and reinforced or modified existing EPA regulator programs for both stationary and mobile sources of air pollution.

The 1977 amendments required that, by Dec 6, 1977, each state submit to EPA documentation of the attainment status of its air-quality-control regions for each of the pollutants for which national ambient air-quality standards (NAAQS) had been promulgated. Areas with air quality better than NAAQS would be designated as a prevention of significant deterioration (PSD) area for these pollutants. In areas where the air quality did not meet NAAQS for these pollutants, they would be classified as nonattainment (NA) areas.

The 1977 amendments required that the states revise their implementation plans to incorporate PSD requirements, thus assuring that areas meeting the NAAQS would continue to maintain satisfactory air quality. These SIP revisions were to be completed by the states by Dec 1, 1978. Not all states met this schedule, however.

Similarly, states must revise their SIPs for areas which were in a NA status to provide for meeting the primary ambient air-quality standards by Dec 31, 1982. A five-year extension, to Dec 31, 1987, was allowable for achieving compliance for photochemical oxidants and carbon monoxide. These SIP revisions were to be submitted to EPA by June 30, 1979.

Stationary source requirements

Both the 1970 and 1977 amendments directed EPA to establish and review air-pollution-control standards for new sources and sources emitting hazardous pollutants and noncriteria pollutants. In response, EPA set up new-source performance standards (NSPS), which applied to certain types of new industrial plants and municipal facilities, as well as to the expansion or modification of existing plants. Under these standards, the best available pollution-control technology (BACT) must be implemented. Under the 1977 amendments, these standards must be reviewed to ensure that they are consistent with PSD requirements.

The PSD provision was primarily intended to protect clean-air areas of the country already meeting air-quality standards from polluted air emissions by new and expanding industrial plants.

The PSD concept was developed by EPA in the early 1970s and was affirmed by Congress in the 1977 amendments. Under these amendments, clean-air areas must be divided into three classes: *Class I,* in which very little air-quality deterioration would be allowed; *Class II,* in which only moderate air-quality deterioration would be allowed; and *Class III,* in which more significant deterioration would be allowed (as long as ambient standards were not exceeded). Congress designated large national parks and wilderness areas as *Class I.* All other lands were *Class II* unless redesignated either *Class I* or *Class III* by a state governor.

Proposed PSD revisions

Last June, the US Court of Appeals for the District of Columbia invalidated or questioned many of EPA's PSD regulations, as a consequence of a suit against EPA by Alabama Power Co. In response to this court decision, EPA proposed revised PSD rules in August. But they will not be final, or even well understood, for many months. The court ruling and subsequent proposed revisions are extensive and complicated, but there are a few key features:

In industry's favor is the proposed new

rule that PSD reviews only apply to major emission sources, which emit or have the potential to emit 100 to 250 tons/yr (depending on the source category) of any regulated pollutant *after applying air-pollution controls.* The old PSD rule required review *before* applying air-pollution controls. This will reduce the number of smaller sources that require PSD review.

The court also ruled that EPA could not include fugitive emissions in calculating total emissions potential, because of the uncertainties in estimating their impact. EPA must now regulate fugitive emissions separately—but it has proposed a list of specific plant types where fugitive emissions can be measured accurately.

Under the proposed new rules, PSD review would apply only to sources within the clean-air area, unless the source would have an adverse impact on a PSD area in another state. EPA is concerned, however, that sources controlled to protect Class I areas could go uncontrolled, leading to significant air-quality deterioration in these areas.

The court decision states that sources that do not need PSD review must be analyzed more extensively. The review must include emissions of any amount of any pollutant that is regulated under the Clean Air Act. This includes criteria pollutants, hazardous air pollutants, and pollutants regulated in any NSPS. Proposed PSD regulations would require that BACT be applied to all pollutants regulated under the Clean Air Act where construction and operation would cause significant net emission increases.

NSPS activities

New-source performance standards were adopted for electric generating plants on June 11, 1979. According to EPA, NSPS will increase utility costs by approximately \$3.6-billion/yr by 1985, and will add more than 2% to the average monthly residential electric bill. Some 350 new power plants expected to be built by 1995 will be affected by these new standards.

NSPS require SO_2 emission control to 1.2-lb $SO_2/10^6$ Btu heat input. An additional requirement calls for removal of 90% of SO_2 emissions from high-sulfur coal, and 70% from coal with potential emissions of 0.6 lb $SO_2/10^6$ Btu heat input. These standards are less severe than the ones proposed by EPA last year, which called for 85% reduction of SO_2 from all types of coal, with stringent compliance requirements.

A less-controversial feature of the proposed new standards sets particulate emissions at 0.03 lb/10^6 Btu heat input (the earlier proposed standard was 0.1 lb/10^6 Btu) from solid, liquid, or gaseous fuels. In addition, the nitrogen oxides emission standard is 0.2-0.8 lb $NO_x/10^6$ Btu heat input, depending on the type of fuel used.

EPA must review and promulgate NSPS for a large number of industrial categories by August 1982. These categories, and the EPA-assigned priority for promulgating the standards, were published in the *Federal Register* Aug 21, 1979. Currently, NSPS have been proposed by EPA for the following industries or categories: internal-combustion engines, phosphate-rock processing, glass manufacture, and automobile and light-duty-truck surface-coating operations. NSPS will also be proposed for lead-acid-battery manufacturing.

NSPS for perchloroethylene dry-cleaning plants will be proposed by year-end, as will standards for nonmetallic minerals and organic-solvent metal cleaning. Nearly everyone should be interested in the NSPS for industrial boilers, which are still in the early development stage. EPA expects to propose these standards next November.

Another key provision of the 1977 amendments deals with air-quality NA areas. It allows industrial development in air-quality-control regions that violate air-quality standards, but only under stringent conditions. The addition of pollutants to the atmosphere from new sources in these regions must be more than offset by the further removal of pollutants from nearby existing sources by means of shutdowns, process changes, or additional pollution-abatement equipment.

New plants must attain an emission limitation that is the lowest achievable emission rate, and the emission offsets obtained must result in a positive net air-quality benefit that provides reasonable process toward attainment of applicable air-quality standards. All existing facilities owned by the company commissioning the new plant must be in compliance with applicable emission limits and standards.

National emission standards

The Clean Air Act amendments grant EPA the authority to establish two types of national emission-control standards—NSPS and NESHAPS. NSPS derive from Section 111 of the act, which authorizes EPA to establish standards of performance for new or expanded stationary sources of pollution. They call for the application of the best technological systems of continuous emission reduction, which EPA determines has been adequately demonstrated.

In making this determination, the administrator must take into consideration the cost of achieving such emission reduction, any non-air-quality impacts, and energy requirements. New industrial plants, therefore, must implement the best emissions-control technology that has been adequately demonstrated, thus allowing continued industrial growth without compromising the goals for attaining and maintaining clean air.

The act calls for EPA to establish NSPS for stationary sources that have a significant impact on the environment. EPA has developed NSPS for over 20 industrial categories. The specific air pollutants covered in one or more of these categories are particulates, sulfur oxides, nitrogen oxides, sulfuric acid, carbon monoxide, and hydrocarbons.

Hazardous air pollutants are defined in Section 112 as pollutants for which no ambient air-quality standard has been set, but which may cause an increase in mortality or serious illness. The act allows EPA to establish a list of hazardous air pollutants and to develop emission or design standards to cover both new and existing emitting sources. Standards have been developed by EPA thus far for these hazardous air pollutants: beryllium, asbestos, mercury, and vinyl chloride. Standards will be proposed for benzene in 1980.

The Clean Water Act amendments of 1977

The 1977 amendments to the Federal Water Pollution Control Act—now termed the Clean Water Act—essentially set mid-course corrections for the 1972 amendments. An important emphasis of the Clean Water Act is the control of toxic substances in wastewater. For the control of toxic pollutants, industry must achieve the best available treatment (BAT) requirements of the law no later than July 1, 1984. This constitutes a one-year extension of the BAT deadline specified in the 1972 amendments.

The toxic pollutants of concern will include at least the 65 substances identified in the EPA/Natural Resources Defense Council (NRDC) consent decree (see POWER Special Report, *Water-pollution control in steam plants,* April 1977). The agency has compiled a working list of 129 specific chemical pollutants from the 65 classes identified in the consent decree. It is required that effluent guidelines setting BAT levels of control for all these pollutants in 21 industrial categories be promulgated by July 1, 1980. (The lists of pollutants and industrial categories were published in the *Federal Register.*)

EPA and NRDC reached an agreement in mid-December 1970, to extend both regulatory and toxic pollutant-control deadlines by one year. The district court for the District of Columbia approved the EPA/NRDC agreement in March 1979; thus, plants have until June 30, 1984, to comply with BAT, toxic-pollutant and effluent guidelines, and pretreatment standards.

Pretreatment standards apply to industrial plants that discharge their wastewater to Publicly Owned Treatment Works (POTWs). EPA has estimated that up to 25% of the waste received by POTWs is from industrial sources. Where industrial wastewater containing toxic pollutants enters municipal sewers, three kinds of problems can develop:

- High volumes or concentrations of certain toxic pollutants can upset the proper operation of biological waste-treatment systems.
- Toxic pollutants entering a POTW can be partially removed with the waste sludge—and sludge contaminated with toxic pollutants may be unusable as a soil conditioner. Improper handling of such sludge can result in uptake of these pollutants by crops in the human food chain, or in leaching of the pollutants into groundwater.
- Toxic pollutants may pass through POTWs in quantities that can be harmful to the environment, which can violate applicable pollution-control regulations or prevent the recycle or reuse of the treated municipal wastewater.

Both EPA and industry now are studying wastewater streams associated with the use of coal—including bottom-ash sluice water, flyash sluice water, wastewater from flue-gas scrubbers, and coal-pile runoff. Some of these coal-related wastewaters contain varying concentrations of toxic heavy metals.

Flyash is a potential source of toxic material when transported by water from electrostatic precipitators to a settling bond or clarifier. It can include several ppm of iron, nickel, and zinc along with trace quantities of chromium, copper, lead, arsenic, and cadmium. Bottom-ash sluice water has essentially the same constituents, but usually in lower concentrations.

Flue-gas desulfurization systems, particularly those currently being installed in the East, often are designed for zero aqueous discharge. Operation of these systems, therefore, would not be regulated by the Clean Water Act. But since residues from these systems generally are disposed of in some type of landfill, they fall under RCRA.

Treatment processes

Current heavy-metals removal technology consists of chemical softening using lime, caustic, soda ash, or sulfites. Spent sludges produced by these wastewater-treatment processes, however, will be considered special hazardous wastes under RCRA.

Table 4: States and territories with NPDES responsibility delegated from EPA*

State	Date assumed NPDES authority
California	May 14, 1973
Oregon	Sep 26, 1973
Connecticut	Sep 26, 1973
Michigan	Oct 17, 1973
Washington	Nov 14, 1973
Wisconsin	Feb 4, 1973
Vermont	Mar 11, 1974
Ohio	Mar 11, 1974
Delaware	Apr 1, 1974
Mississippi	May 1, 1974
Montana	Jun 10, 1974
Nebraska	Jun 12, 1974
Georgia	Jun 28, 1974
Kansas	Jun 28, 1974
Minnesota	Jun 30, 1974
Maryland	Sep 5, 1974
Missouri	Oct 30, 1974
Hawaii	Nov 28, 1974
Indiana	Jan 1, 1975
Wyoming	Jan 30, 1975
Colorado	Mar 27, 1975
Virginia	Mar 31, 1975
South Carolina	Jun 10, 1975
North Dakota	Jun 13, 1975
Nevada	Sep 19, 1975
North Carolina	Oct 19, 1975
New York	Oct 28, 1975
Virgin Islands	Jun 30, 1976
Illinois	Oct 23, 1977
Tennessee	Dec 28, 1977
Pennsylvania	Jun 30, 1978
Iowa	Aug 10, 1978

*Sources: (1) *Environmental Quality*, 7th annual report of the Council on Environmental Quality; (2) personal communication, EPA Office of Water Enforcement, Permits Div.

Depending on the stringency of the EPA effluent guidelines for toxic substances and the nature of specific waste streams, the requirements for wastewater-treatment equipment for individual plants may vary widely.

Industry should consider conducting waste-characterization and treatability studies soon, to identify the best method for treating its waste streams. Be aware that all plants must have a national pollutant-discharge-elimination system (NPDES) permit to discharge *treated* wastewater directly into a navigable waterway. The permit system will ensure that the plants comply with effluent guidelines now being prepared.

Authority to issue NPDES permits rests with EPA; it may, however, be delegated by the agency to state pollution-control agencies. So far, EPA has given NPDES authority to 32 state agencies (Table 4), and several more are under consideration. EPA and the states use the various effluent guideline studies to determine discharge standards.

By mid-1978, EPA and the states had issued permits to about 7700 major dischargers and almost 45,000 minor dischargers. Permits typically consist of effluent standards, a schedule for achieving them, and monitoring and reporting requirements. Enforcement of effluent standards is the responsibility of EPA or the state that issues the NPDES permit. Enforcement of pretreatment standards is left primarily to the municipalities, with some support from state agencies. EPA is expected to enforce pretreatment standards only in extreme cases.

As part of its effluent-guidelines program, EPA has developed NSPS that apply to industrial plants if construction commences after the standards for that particular industry have been promulgated. The Clean Water Act requires that EPA issue these standards to specify the "greatest degree of effluent reduction achievable through use of the best-available demonstrated control technology." NSPS requirements are applied to specific plants through issuance of NPDES permits.

Where NSPS are applied to a new industrial plant, a 10-yr protection clause is added to the permit. This clause provides that a new plant built in compliance with NSPS is to be protected against any tightening of the standards for a period of 10 years after it commences operation, or for the period of depreciation or amortization under Sections 167 or 169 or the Internal Revenue Code, whichever is less.

Conventional pollutants

Besides toxic pollutants, EPA effluent guidelines and NPDES permits also must consider these conventional pollutants: five-day biochemical oxygen demand, total suspended solids, fecal coliform bacteria, oil and grease, and pH. EPA has proposed adding others to the list, such as phosphorus and chemical oxygen demand. Since the 1972 amendments, effluent guidelines developed for various industries generally have addressed the conventional pollutants listed above. Those applicable to waste streams directly associated with coal use are total suspended solids, pH, and oil and grease.

The Clean Water Act dictates that EPA determine the best conventional treatment (BCT) technology for conventional pollutants that exist in each major industry. Many experts expect that BCT will be no more stringent than BAT which, in most cases, already has been established for the various industry groups. The deadline for industry implementation of BCT technology is July 1,

1984, the same as for toxic-pollutant control.

On Aug 28, 1979, EPA withdrew BAT requirements for conventional pollutants in 64 industry groups, replacing them with less-stringent BCT requirements. EPA estimates that this action will save the affected industries up to $200-million in water-pollution-control costs. Affected industries include cement, ferroalloys, glass, dairy, and food processors.

Nonconventional pollutants

The final category of pollutants regulated by the act—the so-called nonconventional pollutants—includes substances that do not fit into either the toxic- or conventional-pollutant categories. Nonconventional pollutants probably will include such substances as aluminum, ammonia, and chlorine. EPA's deadline for meeting BAT effluent guidelines is three years after promulgation, but certainly no later than July 1, 1987.

Thermal discharges do not fall into either the conventional or nonconventional categories of pollutants. Rather, heat is covered under the Clean Water Act as an entirely separate pollutant, subject to BAT requirements except as they may be modified in Section 316 of the document.

One of the new features embodied in the Clean Water Act is Section 304 (e), which authorizes the EPA administrator to issue supplemental regulations for any toxic or hazardous pollutant identified in Section 307 (a) or Section 311, to ensure that an industry maintains the best environmental-management practices (BMP) at operating sites. According to the House/Senate conference report, the intent of this provision in the law is primarily to control runoff of toxic and hazardous materials from industrial sites that results from poor or inadequate housekeeping procedures.

Implementation of EPA's authority is completely discretionary, but the agency will very likely incorporate a provision in NPDES permits requiring that industrial plants comply with any future regulations of management practice, whether such regulations are promulgated before or after the permit is granted. Examples of such regulations that could be developed by EPA over the next several years include:

- Use of a tank or other form of cover over the coal pile to prevent rainwater from picking up toxic pollutants from the coal and then flowing to a nearby stream or lake.
- Containment measures for coal-pile runoff, such as dikes.
- Lining of ash ponds to prevent seepage of pollutants into ground water.
- Control of biocide-treatment practices of cooling water to help reduce the presence of toxic substances in cooling-tower blowdown.

Several forward-looking electric utilities already are incorporating some of these features into new power plants. Over the long term, environmental-management practices will become a more commonly used regulatory tool, and waste-management practices in industrial plants will be as important as end-of-pipe treatment.

Superfund being considered

Last June, the Administration proposed legislation to provide a superfund to pay for emergency cleanup and containment of oil, hazardous-substance spills, and abandoned or inactive hazardous-waste spills. The superfund, containing $1.6-billion, would be financed 80% by fees on the oil and chemicals industries and 20% by federal appropriations. The money would be used to cover liability, compensation, and cleanup of oil and chemical spills and dangerous abandoned hazardous-waste sites.

Section 311 of the Clean Water Act already authorizes a $35-million fund to pay for any costs to EPA or the Coast Guard to clean up or dispose of spilled chemicals. The federal government is allowed to recover such costs from the responsible parties up to $50-million per incident—and in the case of willful negligence, there is no limit to the discharger's liability. Responsible parties also can be fined up to $50,000, or $250,000 if the spill results from willful negligence or misconduct.

An EPA spokesman recently noted that the Section 11 fund is inadequate to deal with the large number of oil and chemical spills that occur. The recent Mexican oil spill that hit the Texas coast has required that $4-million be authorized from the fund for cleanup purposes. If the spill continues, cleanup efforts for this one spill could conceivably exhaust the $35-million fund.

The Fuel Use Act of 1978 replaces ESECA

The Powerplant & Industrial Fuel Use Act of 1978 (FUA) was signed into law by President Carter on Nov 9, 1978, and became effective on May 8, 1979. This legislation replaced the Energy Supply & Environmental Coordination Act of 1974 (ESECA), the nation's first attempt to order industrial plants away from oil and gas (POWER, July 1975, p 33).

The authority granted the government by ESECA, including the power to issue orders that would prohibit the burning of oil and gas in large plants with coal-burning capability, expired Dec 31, 1978. Prohibition orders issued under ESECA still hold, however, except for a few installations that were given the option of complying with ESECA orders or being regulated by FUA.

FUA is expected to be more effective in forcing conversion to coal than ESECA, which had almost no tangible impact on fuel-use policies. One of the principal reasons is that FUA empowers DOE to prohibit the use of petroleum and natural gas, or to require minimum percentages of an alternative fuel at virtually every major fuel-burning installation (MFBI) in the US.

The burden of proof is determining who should be exempt from the DOE prohibitions now rests squarely with industry—not with the government, which was the case with ESECA.

Facility categorization

An MFBI is defined as any installation having either (1) a stationary combustion unit with the capacity for burning 100-million Btu/hr or more of any fuel, or (2) any combination of two or more combustion units at the same site with the combined capacity for burning 250-million Btu/hr or more of any fuel. In determining the aggregate site capacity, only units with capacities of 50-million Btu/hr or more are counted.

Pumps and compressors used solely for the purpose of producing, handling, or distributing gases or liquids are not considered. MFBIs that are provided exemptions for such uses are filed with and approved by DOE.

Prohibitions and exemptions issued by DOE will vary between "new" and "existing" facilities. Any installation for which construction or acquisition begins before DOE issues prohibitions will be considered an existing facility. New facilities are those beginning acquisition after an applicable prohibition is issued. In addition, DOE actions will vary between new boilers and new nonboilers. The category of nonboilers includes such units as gas turbines, gas cycle units, internal-combustion engines, and fired process heaters.

Prohibitions under FUA

The use of petroleum or natural gas for only new industrial-boiler MFBI is prohibited by FUA. Regarding new nonboiler MFBIs, the Secretary of Energy has the authority to ban use of oil and gas for specific categories of plants by a general rulemaking. He also has the power to ban the use of oil or gas by

issuing orders on a case-by-case basis, even if a new nonboiler MFBI is not in a prohibited category.

Categories of existing MFBIs with design capabilities of consuming 300 million Btu/hr or more of fuels can be prohibited from using gas or oil by DOE. Smaller-capacity existing MFBIs can be issued prohibition orders on a case-by-case basis.

Existing MFBIs that have or previously had the technical capability to use an alternative primary fuel, and could switch from gas or oil without substantial physical modification of the unit or significant reduction of capacity, may be banned from using gas or oil, provided such a switch is deemed as financially feasible.

Prohibitions for new MFBIs will be based on the technical feasibility of changing fuels, facility size, location, and other relevant factors.

Prior to issuing exemptions allowing the use of gas or oil at an individual installation, DOE must be satisfied that consumption cannot be partially reduced by using an alternative fuel for a portion of the facility's needs. The use of fluidized-bed combustion methods must also be ruled out as economically or technically unfeasible before an exemption is granted.

Temporary exemptions

Temporary exemptions are granted for a period of five years, and can be extended by DOE to a maximum of ten years. Any MFBI can be granted a temporary exemption if an alternative fuel supply is not available, if significant site limitations exist, if environmental requirements cannot be met by switching fuels, or if synthetic fuels will be used after the exemption expires.

DOE can grant a temporary exemption for lack of an alternative fuel if it is likely that an adequate and reliable supply of coal or other alternative fuel of the quality necessary would not be available to the unit operator during the time of the temporary exemption "at a cost which, based on the best practicable estimates, does not substantially exceed the cost of using imported petroleum as a primary energy source."

An exemption also can be granted if conversion to coal would violate "applicable" environmental laws, either state or federal, or if site limitations—such as a lack of transportation facilities for an alternate fuel, a lack of land for the necessary fuel handling, or the lack of sufficient water—would prevent fuel switching.

In each of these cases, the operator must show DOE that he has made a "good-faith effort" to try to comply with the prohibition, and must demonstrate that, "despite such efforts, he will be unable to do so for the period of the exemption."

DOE can issue an exemption to a plant operator if he demonstrates that, after the five-year exemption, the unit in question will be using synthetic fuel derived from coal or another fuel. The operator also must show that the unit could not use synthetic fuel until the end of the exemption. To qualify for the exemption, a compliance plan, which includes evidence of a binding contract with a synthetic-fuel supplier, must be filed with DOE.

A new MFBI can receive a temporary exemption if it demonstrates, with binding contracts and state construction permits, that an alternative fuel will be used for at least 75% of the required heat input after the exemption expires. To qualify for this exemption, the installation must have a heat-input design capacity of less than 300-million Btu/hr.

Existing MFBIs are eligible for a temporary exemption if, at the end of the exemption period, the operator will comply with the prohibition either by switching to an "innovative" technology which uses an alternative fuel or by permanently retiring the unit in question.

Permanent exemptions

Permanent exemptions, like temporary exemptions, may be granted to any MFBI where, "despite diligent good-faith efforts," an adequate supply of an alternative fuel will not be available, one or more site limitations exist, or applicable environmental requirements would be violated. Also, new facilities can be permanently exempt if the use of an alternative fuel would prevent the owner from obtaining sufficient capital for financing.

DOE can make permanent exemptions in cases where local or state laws, or building codes, would make unfeasible the siting or operation of a facility using coal or another alternative fuel. The conferees' report, however, explicitly directs DOE not to recognize a state or local law if "it is clear that law was established . . . to aid the affected power plant or installation to be granted an exemption," or to help the operators of the units "preclude the use of coal or alternative fuels in preference for gas or oil."

Cogeneration for heat recovery can be grounds for receiving a permanent exemption as long as the benefits of cogeneration are not obtainable unless petroleum or natural gas is used as a boiler fuel.

A permanent exemption can be granted if a mixture of gas or oil and an alternative fuel is to be used. To be eligible, the use of oil or gas must be required to "maintain operational reliability of the installation consistent with maintaining a reasonable level of fuel efficiency." If the exemption is granted, DOE will not require that the percentage of petroleum or natural gas used in the mixture be less than 25% of the total annual Btu heat input of the installation.

A facility may be granted a permanent exemption if it is to be maintained and operated for "emergency" purposes only, as defined by the Secretary of Energy, or if the exemption is required to meet scheduled equipment outages. In certain cases, the use of natural gas from an international pipeline is also sufficient grounds for receiving a permanent exemption.

The Economic Regulatory Administration (ERA) of DOE is currently reviewing requests for exemptions under FUA. As of this writing, it is estimated that several months will be required to review the large volume of requests submitted. ERA will process most of them before beginning to issue prohibition rules and orders. This means that bans on the use of gas and oil at specific facilities and categories of facilities are not likely to be made before the spring of 1980. After the publication of a final prohibition rule or order in the Federal Register, the affected facility will have 60 days to apply for an exemption.

Energy board pending

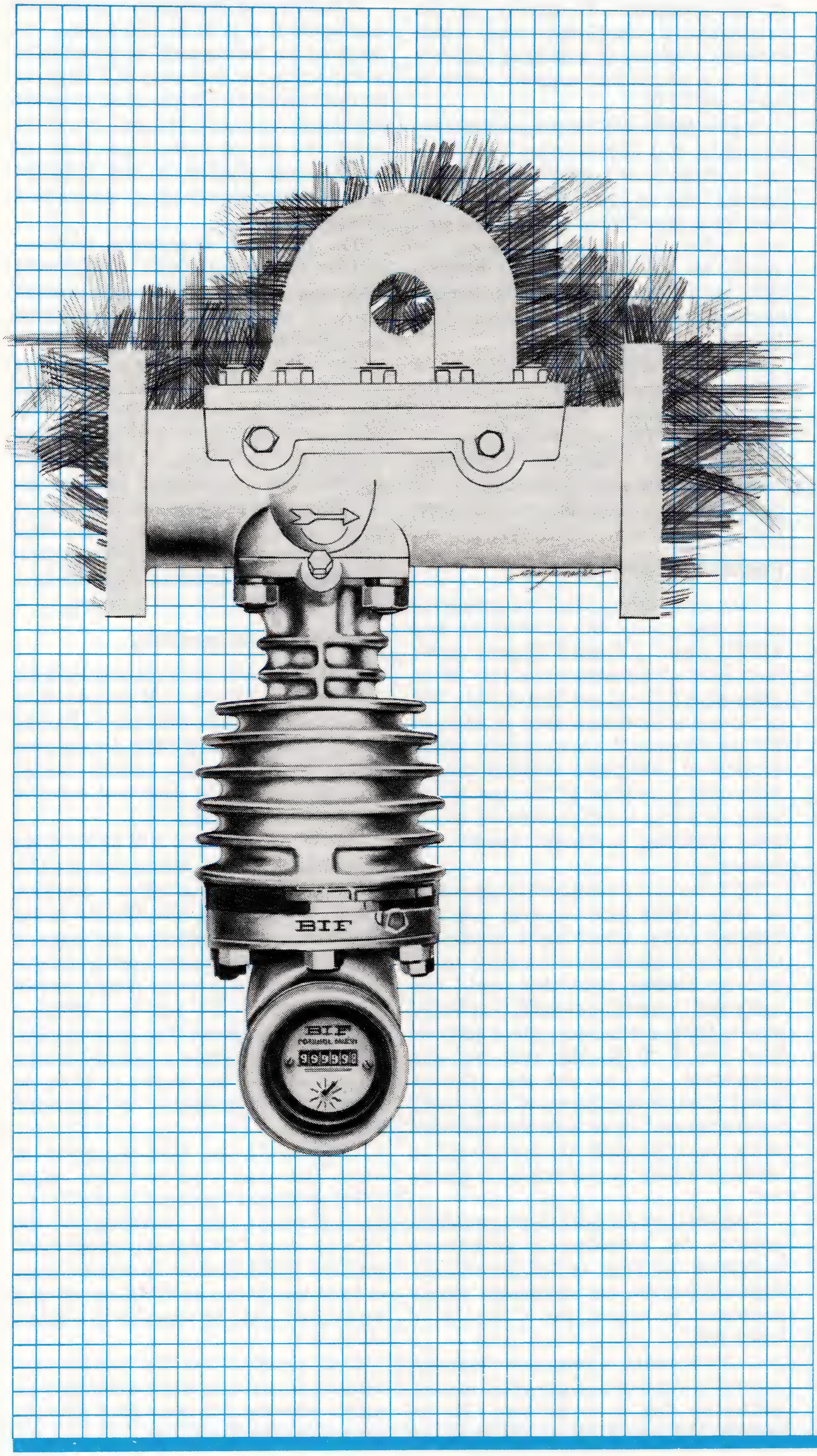
At President Carter's request, both the Senate and the House of Representatives have drafted bills to establish an Energy Mobilization Board (EMB). Its function would be to expedite priority energy projects through the perpetual maze of government red tape.

Two House bills are still in the stage of committee review, but on Oct 4, 1979, the Senate passed a bill to establish EMB. According to this bill, the board would have the authority to make a decision for a regulatory agency regarding a designated priority energy project if that agency did not act within a proposed maximum two-year period. EMB could designate a priority energy project only if the project is likely to reduce US dependence on imported energy.

EMB would also have the power to waive state and local laws that might affect designated priority energy projects. However, the Secretary of the Interior or the EPA Administrator could veto any EMB decision to waive a state or local law. Either an EMB waiver or a veto action could be appealed to a federal court.

It is possible that the Senate may amend and revise its bill in a compromise action with the bill that will eventually come from the House. ■

Steam Cost Accountability



BIF's direct-reading, turbine type Shuntflo® meter tells precisely how much steam is being used in each building, segment, or process. It's a totalizing meter, designed to measure the flow of steam up to 300 psig and 750°F. Provides an accumulative record of actual flow in pipe sizes 1" to 20".

The meter accurately registers rates up to 150% of rated capacity and can handle overloads of up to 200% for short periods. Accuracies of ±2% of actual flow can be achieved.

Installation is as easy as for a flanged pipe section in most applications. Completely self-contained and self-operating, the meter requires no mercury, pressure piping, compressed air, or electrical power. Options include: pressure compensator; electric contactor to operate remote totalizer and/or demand meter; choice of digital or pointer counter.

Low maintenance, magnetic drive design eliminates leakage problems common to mechanical drive units. Counter can be removed or replaced without shutting off flow. Capacity can be quickly modified by simple change of internal orifice plate.

Every Shuntflo meter is individually tested and calibrated to the customer's specific steam flow conditions and is shipped ready for service.

For literature, contact BIF, 1600 Division Road, West Warwick, RI 02893. 401-885-1000.

A UNIT OF GENERAL SIGNAL

BIF®

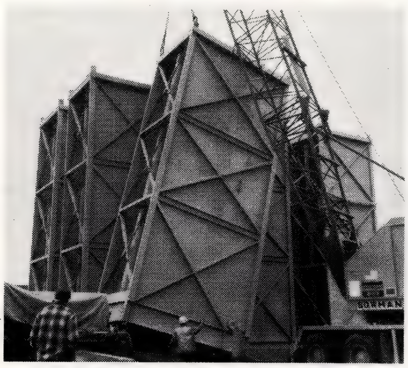
Basic In Flow

Vogt Boilers Perform. All Ways.

Every industry has power requirements. But each user is faced with different specifications and job site conditions. For that reason, Henry Vogt Machine Co. manufactures boilers to meet a variety of applications.

Module Steam Generators

The Module Steam Generator (MSG) is a high-efficiency heat recovery boiler that converts gas turbine exhaust heat into usable steam for power. It is designed of standard components by Vogt engineers and has wide-range applications to



meet the requirements of varying gas turbine and steam conditions.

The MSG is constructed from heavy-gauge steel casing with structural X-braces on both sides, giving it strength and stress capabilities equal to the rigors of domestic and international shipping. On site, the MSG can be lifted from a rail car, turned upright and set on its foundation by the use of a single crane.

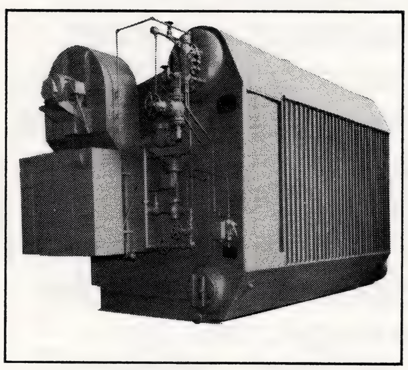
Field-Erected Boilers

Vogt offers field-erected designs in a wide range of boiler types, all with customer design features and conservative rating limits.

With Vogt field-erected boilers our design engineers work with you to determine the design that will adapt best to your site conditions. The teamwork approach is essential when considering furnace size, configuration, degree of water cooling, combustion and heat transfer standards and fuel and burner and/or stoker requirements.

Package Boilers

The Vogt "DT" Package Boiler meets the increasing demand for a low cost, compact, gas and oil-fired, shop-assembled steam generator. The "DT" unit is designed to produce steam quantities up to 150,000 pounds per hour when equipped with an air heater or economizer. A superheater can be

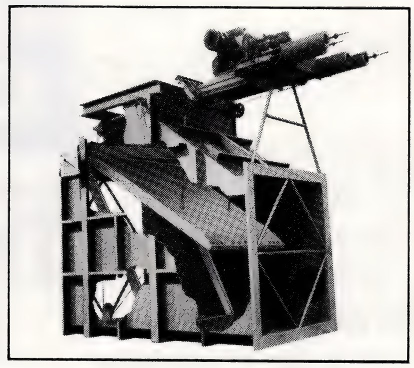


installed to raise the final steam temperature to 750°F when operating at pressures up to 750 psig.

Vogt Package Boilers are available in several standard sizes and can be offered for quick delivery and low cost when power requirements can be satisfied by a package unit.

Airline Dampers

The warping and leaking of dampers in hot gas ducts at elevated temperatures makes usual damper utilization an unreliable, high-



maintenance operation. The Vogt Airline Damper changes all that. Even at operating temperatures in excess of 850°F, the Vogt Airline Damper design assures tight shut-off with no leakage. This is possible through the compression of a unique heavy-duty gasket fixed to a seat angle around the inside of the duct.

Vogt engineers have successfully addressed the problems of power generation, waste heat recovery and hot-gas flow since 1880. They stand ready to serve you with equipment and expertise, both now and in the future.

We Want You To Know. Henry Vogt wants you to know about our complete line of boilers, because we want you to know the kind of engineering assistance we can provide, not only in boilers, but also in heat exchangers, valves, fittings and Tube-Ice® machines. For more information, call (502) 634-1511. Or write: Henry Vogt Machine Co., Dept. 24A-PEHB, P.O. Box 1918, Louisville, Kentucky 40201.

Vogt®

Heat Transfer

A quality approach to engineering, equipment and energy savings.

MANUFACTURERS' LITERATURE

201 **Bender protractor provides** a fast and accurate way to lay out conduit angle needs and check conduit bands while bending. Brochure describes how it's constructed and used.—Enerpac.

202 **Unitized combination starter** is covered in bulletin, which describes benefits of current-limiting, visible breaker blades, and coordinated protective systems.—Gould Inc, Distribution & Controls Div.

203 **Molded rubber high-voltage** terminations, splices, and connectors for solid dielectric cable are described and illustrated in 22-page color booklet, which shows a wide variety of actual field installations.—Amerace Corp, Elastimold Div.

204 **Reliability of emergency** power-transfer systems is the subject covered in the last three issues of the newsletter, AscoFacts. Testing, inspection, preventive maintenance, and repair are described.—Automatic Switch Co.

205 **Adjustable-speed ac drives** are described here, with details of standard features, enclosures, optional accessories, and summary specifications on a line of drives from 1 through 500 hp.—Ramsey Controls Inc.

206 **Portable substations** carry the highest possible voltage closest to the point of use. Flyer describes how these units were custom designed and built for a ship-maintenance application.—Electric Technology Corp.

207 **Air-cooled dynamometers** suitable for checking the efficiency of electric motors are described here.—Inductor Inc.

208 **High-voltage** test equipment locates cable faults before catastrophic failure occurs. Complete set of literature also outlines testing procedure.—Von Corp.

209 **Cable raceway systems** and their installation are covered in five tabled sections: methods for determining conduit size, design limits and formulae, example calculations, system considerations, and installations.—Okonite Corp.

210 **Watthour and demand meters** are described in easy-to-follow tabular form with illustrations, application information, and circuit diagrams.—Westinghouse Electric Corp.

211 **Tube expanders and accessories** for heat exchangers and condensers are listed and illustrated in bulletin, which also discusses how to get the most out of your equipment by proper maintenance.—Carrier Corp, Elliott Co Div.

212 **Double-orifice steam trap** is described with design features such as ball check, double-orifice system, and in-line renewal via encapsulated internals. Capacity curves, parts and materials, plus dimensions and weights are included.—Yarway Corp.

213 **Solids-handling submersible** pump bulletin describes how pumps are designed to handle abrasive/corrosive liquids and slurries, such as flyash, construction debris, and industrial waste. Dimensions, weights, and performance curves are included.—Gorman-Rupp Co.

214 **Actuator line includes** electrical rotary- and linear-stroke, as well as worm, spur, and bevel-gear operation. Complete assembly, sales, and servicing operations in the US was recently established. Literature describes product line and lists your representative.—AUMA Actuators Inc.

215 **Hydraulic ratchet wrenches** come in six sizes, electric- or air-powered. Literature describes torquing capabilities from zero to 80,000 ft-lbs, plus complete flexibility provided by nine-point reaction kit that makes the wrench self-locking and self-holding for hands-off operation.—Torque Systems International.

216 **Forged steel valves,** including globes, gates, angles, lift checks, and ball valves, are described in catalog, which covers new temperature rating and other design refinements of this product line.—Jenkins Bros.

217 **Horizontal, centrifugal,** split-case pumps are shown in cutaway illustrations and engineering drawings. Brochure also provides performance charts giving total head and flow parameters for all models, for example, 350 ft at up to 6000 gpm, or 600 ft at 3000 gpm.—Peerless Pump Co.

218 **Butterfly valves** have a thick, void-

free disc and body liner of ultra-high-molecular weight polyethylene, which is precision-molded for maximum abrasion and chemical resistance. Brochure describes use in all types of abrasive service from drilling mud to flyash.—Garlock Inc, Valves & Industrial Plastics.

219 **Gate, globe, and check valves** are described in 150-, 300-, and 600-lb pressure classes in sizes up to 42 in. for the gate valve, 12 in. for the check valve, and 6 in. for the globe valve. Bulletin includes cutaway drawings keyed to parts lists, plus charts of dimensions in both inches and millimeters.—Lunkenheimer-Canada Ltd.

220 **Slurry-pump brochure** contains selection charts, suggested installations, cross-sectional diagrams, and descriptive illustrations. Applications are in mining, utilities, and industry.—Warman International Inc.

221 **Tube-fitting manuals** are programmed for self instruction in the makeup and installation of flared and flareless fittings. Easy-to-follow format covers the principles of tube-end preparation, fitting, make-up, and assembly.—Parker Hannifin Corp.

222 **Drop oil-bath filter concept** provides extremely low pressure loss, and does not need any external power for oil handling. Filters are recommended for cleaning intake air to engines, compressors, and blowers.—Air-Maze Incom International Inc.

223 **Water-purification brochure** describes standard and custom components and systems, from filters, absorbers, and water softeners suitable for water pretreatment to deionizing equipment in various configurations. Chart summarizes the contaminant-removal capabilities and effectiveness of nine types of water treatment.—Vaponic Inc.

224 **Boiler-feedwater-treatment** fact sheet describes the use of an aqueous blend of polymeric dispersants and antifoam agents. Comparative illustration and diagrams show control of iron oxide and hardness deposition.—Betz Laboratories Inc.

225 **Industrial filters** and filter separators, filter elements, instrumentation and flow devices, turbine-oil conditioners, discharge-control systems, and company's new filtration testing laboratory are described and illustrated.—Keene Corp, Filtration Div.

226 **Condensers and heat exchangers** have a novel method of tube support that replaces the drilled support plates and baffle plates in conventional systems with a series of perforated metal strips that lock together in rigid honeycomb structure. Each tube is supported in a precise V-shaped cradle in the honeycomb, giving two kinds of tube contact. Significant increase in longitudinal flow greatly reduces shell-side pressure drop.—Ecolaire Condenser Inc.

227 **Heat exchangers** for general heating and cooling, special CPI processes, air aftercooling, and other applications are described. Shell-and-tube, plate-type, and air-cooled units are listed, as well as steam condensers.—American Standard Co, Heat Transfer Div.

228 **Water-treatment capabilities** are described, including new developments in cooling-water treatment, water clarification, energy additives, and boiler-water treatment.—Dober Chemical Corp, Water Treatment Div.

229 **"High purity water** from the source" describes processes used to produce pure water, equipment used, source-water characteristics to be considered, and the selection of pumps and other components.—Aqua Media.

230 **Packaged boilers** and boiler-room accessories, such as feedwater systems, heat-transfer liquid heaters, control centers, and annunciators, are described.—Aqua-Chem Inc, Cleaver Brooks Div.

231 **Centrifugal fans** with backward-inclined blades are detailed in bulletin that describes two airfoil designs for different air-moving applications. Designed to metric dimensions, the fans are offered in three classes of construction, belt-driven and direct-drive.—Aerovent Inc.

232 **Fuel flexibility with** fluidized-bed combustion packaged boilers is described in brochure. Boilers burn all grades of coal, oil, and natural gas, either individually or simultaneously, with improved efficiency and emission performance.—Johnston Boiler Co.

233 **Energy Monitor** is a computer printout of operating conditions and cumulative energy savings possible from a boiler water-management program. Printout is delivered periodically to commercial and industrial users while they participate in program.—Mogul Corp.

234 **Feedwater heaters** out of service can cost you dollars in lost efficiency and downtime. Company's in-house engineering and manufacturing can repair or replace your heaters quickly.—Perfex Group, Energy Systems Div.

235 **Waste-heat recovery** for make-up or facilities heating uses fan-type heat exchangers installed near an outside wall with appropriate ductwork to channel away heat. A duct switch permits blown hot air to be channeled inside during winter or outside in summer.—American Standard Co, Heat Transfer Div.

236 **Worn V-belt sheaves** can be checked for wear using paper-sheave templates. If the template shows more than 1/32 in. wear the sheave should be replaced. Otherwise it causes rapid belt wear, hot bearings, belt slippage, and wasted energy.—Dayco Corp.

237 **Crushing equipment described** in brochure includes rotary breakers, ring hammermills, impact crushers, and roll crushers. Performance and construction features of equipment are described, and a detailed inquiry form is included for requesting economic evaluations and bid proposals.—Koppers Co.

238 **Bulk materials storage,** handling, and transport; products and services brochure covers turnkey responsibility for customized systems from high-speed log and chip handling to coal-fired production and processing.—Jervis Webb Co.

239 **Oil storage and handling systems** are described in brochure that includes details of properly designed and sized pump and heater sets and storage tanks, as well as accessories, such as conduit systems, wiring, and piping.—Mills, Fife & MacDonald Inc.

240 **"Fuel oil preburner problems"** is a new bulletin that deals with causes and cures for contamination in oil handling systems, including storage tanks, oil preheaters, strainers, burner-tips, pumps, and piping connections.—Drew Chemical Corp.

241 **Fuel economizer** is a highly efficient heat-recovery device. Two brochures describe how it saves fuel by recovering heat from flue gases and putting it to work.—Tranter Inc.

242 **"Terminology of gaging"** is a booklet filled with valuable gaging information terminology and definitions. It also describes a new line of density gages that measures density, specific gravity, or percentage of solids in liquids or solids flowing through pipelines 2-24 in. in diameter.—Ohmart Corp.

243 **Bulk-materials-handling** and fuels-

processing brochure describes the latest systems available for loading, unloading, moving, and storing coal, ash, minerals, and other bulk commodities, as well as systems for sintering ferrous and nonferrous ores, ironmaking, and fuel recovery and conversion.—McDowell-Wellman Co.

244 **Hydroelectric power plants** around the world are described with pictures and diagrams of the hydraulic layout. Benefits of hydroelectric power company's resources are described.—Harza Engineering Co.

245 **Weather-proof housing** for standby generator systems is available to protect and enhance the appearance of company's generator sets, which range in size from 17.5 to 350 kW. Molded of fire-retardant resins, the three-piece fiberglass enclosure measures 7 ft x 12 ft with an 8-ft center height.—Empire Generator Corp.

246 **Turbine energy saving** applications, with before and after data on energy consumption and costs, are described. Included are flow diagrams showing cogeneration using steam from waste-burning boilers and low-pressure surplus steam. Cost savings in purchased power range up to $216,000 a year.—Layman Associates Inc.

247 **Heavy-duty regenerators** for 5000 to 100,000-hp gas turbines reduce fuel consumption up to 30%. Units have demonstrated overall performance of 81 to 87% effectiveness and a pressure drop of 3.5%. Units are reportedly designed to operate for 120,000 hours and 5000 cycles without scheduled repairs.—Garrett Corp, AiResearch Manufacturing Div.

248 **Power-rating chart** covers a complete line of diesels from 30 to 2845 max hp, and provides data on cylinders, bore and stroke, displacement, maximum torque, brake horsepower at various speeds, deductions for altitude and temperature, and other information.—Dresser Industries Inc, Waukesha Div.

249 **Digital readout-temperature** indicators and designed for use with a variety of thermocouples, thermisters, or RTDs. Each unit has a simple interchangeable plug-in module to convert to one of 13 different ranges and calibrations. A switch allows easy conversion from Celsius to Fahrenheit.—Omega Engineering Inc.

250 **Conductivity instruments,** monitors, controllers, and accessories for use in the measurement and control of water purity are described in brochure. Products detailed include a hand-held meter, a line of continuous recording monitor systems, and cooling-tower water controllers.—Myron L Co.

251 **Electronic analog controllers,** indicating stations, and recorders have plug-in components to simplify troubleshooting and maintenance. To assemble any type of control station, simply select correct program board and plug in the appropriate standard modules.—Moore Products Co.

252 **Surface temperature** measurements, rate and total heat-transfer measurements to wall surfaces, and local gas-temperature measurements are covered in set of five technical articles by company engineers.—Nanmac Corp.

253 **Load cells, fluid flow** and level sensors, and electrical and thermocouple harnesses are featured here. Brochure shows how company's

MANUFACTURERS' LITERATURE continued

manufacturing capabilities match many commercial, industrial, and military needs.—Revere Corp of America.

254 **Industrial communications** and distributed control system provides an efficient and economical way to integrate programmable controllers, computers, and terminals with monitoring/sensing devices.—Gould Inc, Modicon Div.

255 **Training courses** for technicians who operate continuous air-monitoring networks are offered. Instructors will come to your facility or technicians can go to the training laboratory in Massachusetts. Courses cover operation of almost all brands of recording instruments.—Environmental Research & Technology Inc.

256 **Domes, covers,** and custom specialty work for water and waste facilities are described in catalog, which shows typical installations and details performance data for three types of covers.—Fiberglass Specialty Co.

257 **Air-sampling products,** including constant-flow controlled low-volume air samplers, high-volume air-sampling systems, constant flow controllers, etc, are described in data sheet.—Kurtz Instruments Inc.

258 **Methane monitor** continuously checks the ambient air for methane and nonmethane hydrocarbons. It can simultaneously measure the concentration of total hydrocarbons, total hydrocarbons less methane, or methane alone.—Mine Safety Appliances Co.

259 **Coating-systems catalog provides** charts for rapid determination of best coating system for all types of interior and exterior surfaces under normal and severe exposure. It also contains a corrosion-resistance guide for selection of rust-preventative coatings and description of company's coating products.—Rust-Oleum Corp.

260 **Anticorrosive coatings** brochure includes a simplified painting guide that describes four basic types of coatings used primarily for the protection of electric transmission towers. They're also valuable for heavy industrial maintenance and new construction.—Carboline Co, Subox Div.

261 **Screening equipment** and water/wastewater treatment equipment for electric generating stations are described here, including traveling water screens, trash-rack rakes, chain and scraper collectors, gravity thickeners, and aeration equipment.—Envirex Inc, Industrial Marketing Group.

262 **Lime-recovery systems** and equipment are described with illustrations and flow diagrams showing the general features and operation of systems. Reuse of lime is also described.—Kennedy Van Suan Corp.

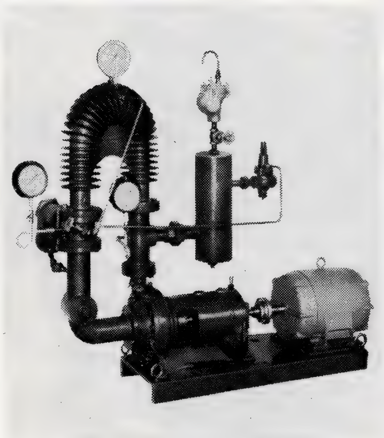
263 **Chilled-water coils,** with removable end-cover plates for complete draining and easy cleaning of tubes, provide energy efficiency and improve performance.—Robert C Burns Assn.

264 **Boiler tube facts** is a pocket-sized encyclopedia on boiler-tube mainte-

(continues on p 123)

Energy saved is money earned.

Cochrane products save on steam, fuel and maintenance.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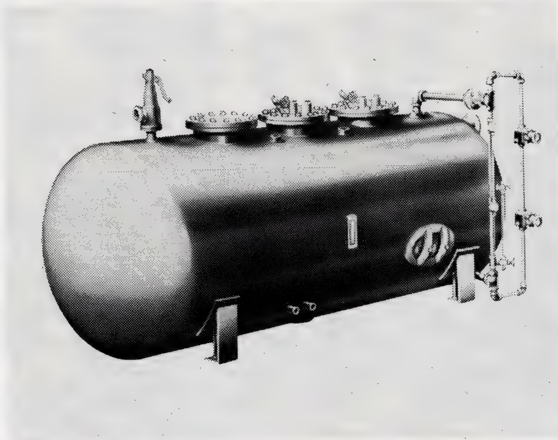
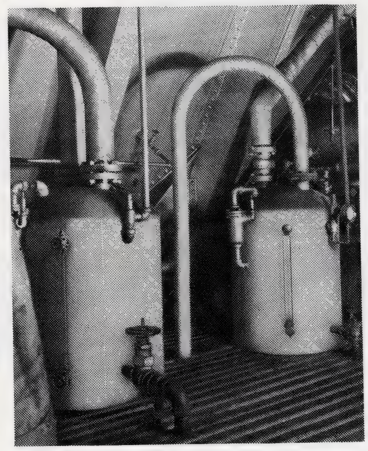

Uni-Mod Deaerator


CBO

As fuel grows scarcer, costs go higher. That fact of life plays a major part in today's purchasing and planning. So the sooner you conserve energy, the sooner you'll begin to save money. Cochrane products help you do both.

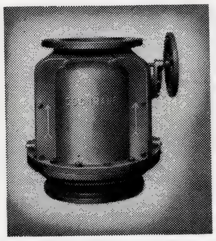
Take our CBA Condensate Booster Drainage Control System. The closed loop, jet-action plus centrifugal pump returns the condensate directly to the boiler so there's no surge and no steam loss from flashing. The fuel you save may well pay for the unit in less than a year.

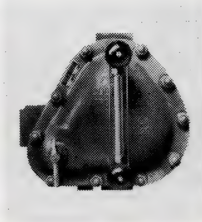
Our Uni-Mod® Deaerators keep boiler feedwater systems corrosion-free. Less fuel is used, and there is less replacement of vital parts.

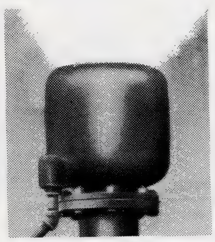
The Cochrane Continuous Blowoff System recovers heat that would otherwise be wasted. Even with small boilers, fuel savings alone with the CBO will be impressive the first year of operation.

For steam control and savings, Cochrane multi-port relief valves provide over-pressure regulation to relieve to the atmosphere safely, and without waste. Condensate drainers handle waste steam continuously and automatically. Our steam exhaust heads cut down on oil particulates, moisture and noise.

Start cutting down on fuel costs, and start saving. Our Cochrane engineers will show you how. For all the details, call or write Crane Co., Cochrane Environmental Systems division, P.O. Box 191 King of Prussia, PA 19406 Tel: 215 265-5050


Multiport


Drainer


Exhaust Head

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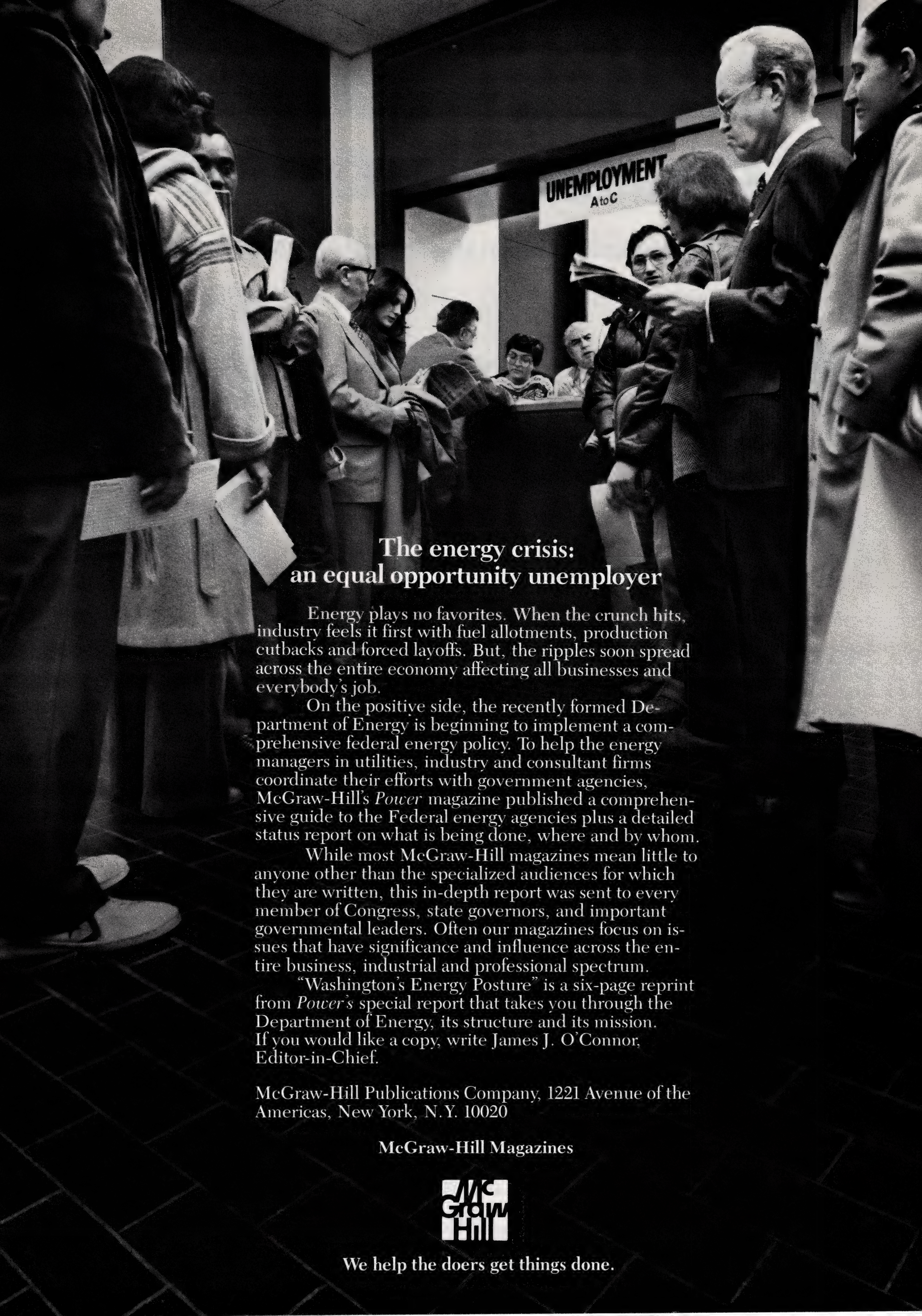
COCHRANE ENVIRONMENTAL SYSTEMS

CIRCLE 121 ON READER SERVICE CARD



The energy crisis: an equal opportunity unemployer

Energy plays no favorites. When the crunch hits, industry feels it first with fuel allotments, production cutbacks and forced layoffs. But, the ripples soon spread across the entire economy affecting all businesses and everybody's job.

On the positive side, the recently formed Department of Energy is beginning to implement a comprehensive federal energy policy. To help the energy managers in utilities, industry and consultant firms coordinate their efforts with government agencies, McGraw-Hill's *Power* magazine published a comprehensive guide to the Federal energy agencies plus a detailed status report on what is being done, where and by whom.

While most McGraw-Hill magazines mean little to anyone other than the specialized audiences for which they are written, this in-depth report was sent to every member of Congress, state governors, and important governmental leaders. Often our magazines focus on issues that have significance and influence across the entire business, industrial and professional spectrum.

"Washington's Energy Posture" is a six-page reprint from *Power's* special report that takes you through the Department of Energy, its structure and its mission. If you would like a copy, write James J. O'Connor, Editor-in-Chief.

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McGraw Hill

We help the doers get things done.

nance that also outlines company's capabilities to respond fast to emergency boiler problems or to act on a stand-by basis for preventative maintenance.—Boiler Tube Co of America.

265 **Consulting services** for power generation are backed by 65 years experience in coal-fired plants, process plants off sites, fuel handling, mechanical, and electrical systems, energy management and conservation, and solar research.—Black & Veatch.

266 **Conserve** steam, fuel, and maintenance with such products as condensate-booster drainage-control systems, deaerators, continuous blow-off systems, multiport relief valves, etc. Company's engineers will show you how.—Crane Co, Cochrane Environmental Systems Div.

267 **Infrared radiant-heating system** puts heat where you need it, down on the floor, warming people and equipment, not air. Catalog describes both oil and gas-fired systems.—Cox Manufacturing Co.

268 **Steam generator** can make your boiler room pay for itself, as shown by case histories, independent test-room comparisons, or an in-plant survey of your operations.—Clayton Manufacturing Co.

269 **Uninterruptible power systems,** ac power sources/frequency converters, ac line conditioners, high isolation transformers, and solid-state inverters are offered.—Elgar AC Power Supplies.

270 **Ash-handling systems,** including pneumatic vacuum systems, pneumatic pressure systems, and hydraulic systems, for fossil-fuel boilers are described in brochure that is of particular value if you are changing fuels or upgrading existing facility.—Allen-Sherman Hoff Co.

271 **Coffin turbo pumps** combine turbine and feed-water pump in an integral unit mounted on a single shaft. There are no couplings and fewer rings or sleeves, so there's less to service and few parts to repair. And it's backed by 24-hour response.—FMC Corp, Turbo Pump Operation.

272 **Optimum insulation thickness** is the amount that will result in lowest total cost for insulation and lost heat over the life of the system. Energy Reduction Analysis is a computer program that determines the optimum thickness for every pipe and tank in your facility.—Johns-Mansville.

273 **Water-quality monitor** measures any water parameter—temperature, conductivity, pH, dissolved oxygen, etc—in fresh or sea water to 300 m depth. Company offers this and many other data acquisition and retrieval systems.—Martek Instruments Inc.

274 **Load programmer** can contain up to eight daily load programs, five different duty cycle programs, and accept temperature or photocell input. Battery back-up will run quartz clock up to 14-days in event of power failure.—Pacific Technology Inc.

275 **Pipe-welding costs** can be reduced with backing rings that fit closely inside pipe, ensuring precise align-

MANUFACTURERS' LITERATURE continued

ment and fit-up and allowing complete penetration and fusion of the weld.—Robvon Backing Ring Co.

276 **Engineering,** construction, operation, and maintenance know-how available from this company will streamline any type of energy facility you may be planning.—Rust Engineering Co.

277 **Flowmeters accurate** to ±0.5% are available to measure liquid flow in diameters from 2 in. to 48 in. and up. Universal Venturi tube flowmeters avoid inaccuracies caused by upstream piping.—BIF Co.

278 **Fuel economizer** is a highly efficient heat-recovery device computer designed to your needs. It can be retrofitted to a boiler to recover waste heat from flue gases and return this heat to the feedwater.—Tranter Inc.

279 **Additives** for low-grade fuels enable plant operators to avoid costly corrosion, deposition, and energy waste, complying with environmental restrictions.—Petrolite Corp, Tretolite Div.

280 **Boilers to meet a variety** of applications are offered, including module steam generators, field-erected boilers, package boilers, etc. Also air-line dampers that won't warp or leak in hot gas ducts up to 850F.—Henry Vogt Machine Co.

281 **Engine-control system** uses microprocessor and analog technologies to provide local or remote monitoring of engine conditions and control of engine loops. Programming is through keyboard or CRT, and system is self-checking with positive shutdown in case of failure. Woodward Governor Co.

282 **Pipeline strainer** is designed for greater effective cleaning area, more efficient backwash, less pressure drop, and is easy to take apart and put back together again.—Zurn Industries Inc, Fluid Handling Div.

283 **Fans for all types** of punishing service are offered in many types and styles with inlet volumes ranging from 150 to 1,000,000 cfm and static pressures to 100 in. water. Bulletin describes fans for light, medium or heavy duty, standard or custom design.—Clarage Fan Co.

284 **Cantilever-shaft pumps** are designed for such problem applica-

(continues on p 129)

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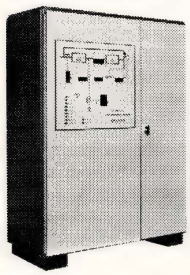

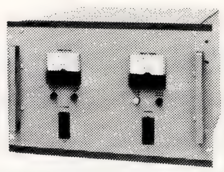

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0.5 TO 45KVA, SINGLE AND THREE PHASE.

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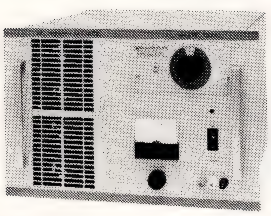

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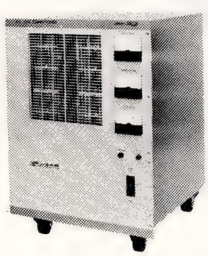
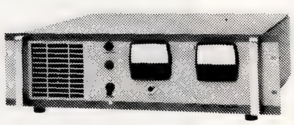
50/60Hz INPUT, 15Hz TO 10KHz OUTPUT, 120VA TO 27KVA.

Elgar's AC Power Sources provide fixed, variable, or programmable output voltages and frequencies with the largest number of single-, two-, or three-phase models available. Typical specifications include 25 microseconds response time, 0.4% maximum distortion and 0.1% regulation.





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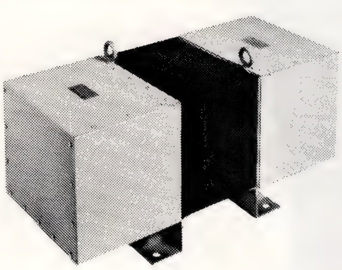

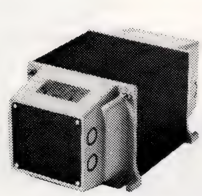

HIGH ISOLATION TRANSFORMERS (HITs)

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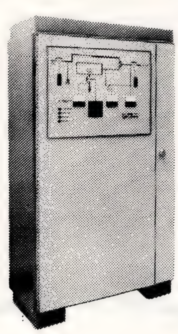
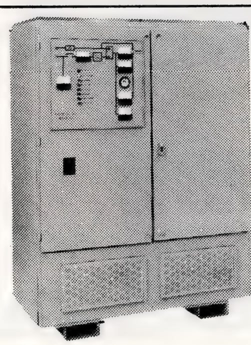
Elgar's HITs are triple-shielded transformers with tightly controlled interwinding capacitance (to 0.0005pF) to virtually eliminate common-mode line noise and other line transients. All HITs are available from stock.





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tions as handling bottom ash, flyash, and coal yard drainage. Pumps can move slurries with up to 70% solids, at temperatures to 1500F. Capacities extend to 12,000 gpm.—Nagle Pumps Inc.

285 **Primer system** helps keep condensers operating at peak efficiency by removing air from the circulating water system.—Nash Engineering Co.

286 **Rubber-seat ball valves** feature E-Lok valve-seating system that offers longer seat life and lower seating torque. Designed for water and wastewater applications requiring throttling or on/off service, the valves come in 6-60-in. sizes for ANSI classes 150 and 300.—Henry Pratt Co.

287 **Compact bronze ball valves** come in sizes from ¼ to 2 in. They feature a large port for full, unobstructed flow, TFE seats, and glass-filled TFE packing. WOG ratings extend from −20 to 100F at 400 psig; saturated steam, 150 psig.—Jenkins Bros.

288 **Automatic controller,** self-contained, is said to regulate reliably sealant fluid flow on centrifugal pumps, compressors, and other rotating machinery with stuffing-box packings or labyrinth seals. Controller senses flow directly, without pressure taps or other indirect elements.—W A Kates Co.

289 **Universal mechanical packing,** Style 200, developed for gunpack-type expansion joints, reportedly is dimensionally stable and resists extrusion. The unsintered PTFE square packing is effective in water and steam systems at temperatures up to 260C over the entire pH range.—A W Chesterton Co.

290 **Pulsation-damping, accumulators,** are designed to protect reactor reciprocating charging pumps and associated piping from pulsations and cavitation-induced fatigue stress. The accumulator has a long-life edge-welded diaphragm nesting-ripple bellows.—Metal Bellows.

291 **Self-cleaning strainer** reportedly offers design simplicity and high performance with less maintenance and lower cost than any competitive unit. Series-595 strainers automatically and continuously remove debris from water and wastewater pipelines ranging in size from 10 to 16 in.—Zurn Industries Inc.

292 **Corrosion Inhibitors** combat pitting, thinning, and failure of condensate piping systems. Nalpac 8246, a combination of three liquid neutralizing amines with different volatility characteristics, neutralizes acid gases.—Nalco Chemical Co.

293 **Manual operators,** spring-return Torq-Handle type, for company's ball valves are designed to return valves to a predetermined position—either open or closed—when the valves are not manually or mechanically held in the operated position.—Jamesbury Corp.

294 **Vic-Tap, a device for** tapping into pressurized piping systems, bolts on to any 6-in. steel pipe and provides a 2½-in. connection in less than 20 min. Unit is UL listed for tapping into fire systems operating under pressures up to 300 psig. Only a standard 120-V connection for the hole saw is required to complete the job.—Victaulic Co of America.

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5	23	41	59	77	95	113	131	149	167	185	203	221	239	257	275	293	311	329	347	365	383	401	419	437	605	623
6	24	42	60	78	96	114	132	150	168	186	204	222	240	258	276	294	312	330	348	366	384	402	420	438	606	624
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15	33	51	69	87	105	123	141	159	177	195	213	231	249	267	285	303	321	339	357	375	393	411	429	447	615	633
16	34	52	70	88	106	124	142	160	178	196	214	232	250	268	286	304	322	340	358	376	394	412	430	448	616	634
17	35	53	71	89	107	125	143	161	179	197	215	233	251	269	287	305	323	341	359	377	395	413	431	449	617	635
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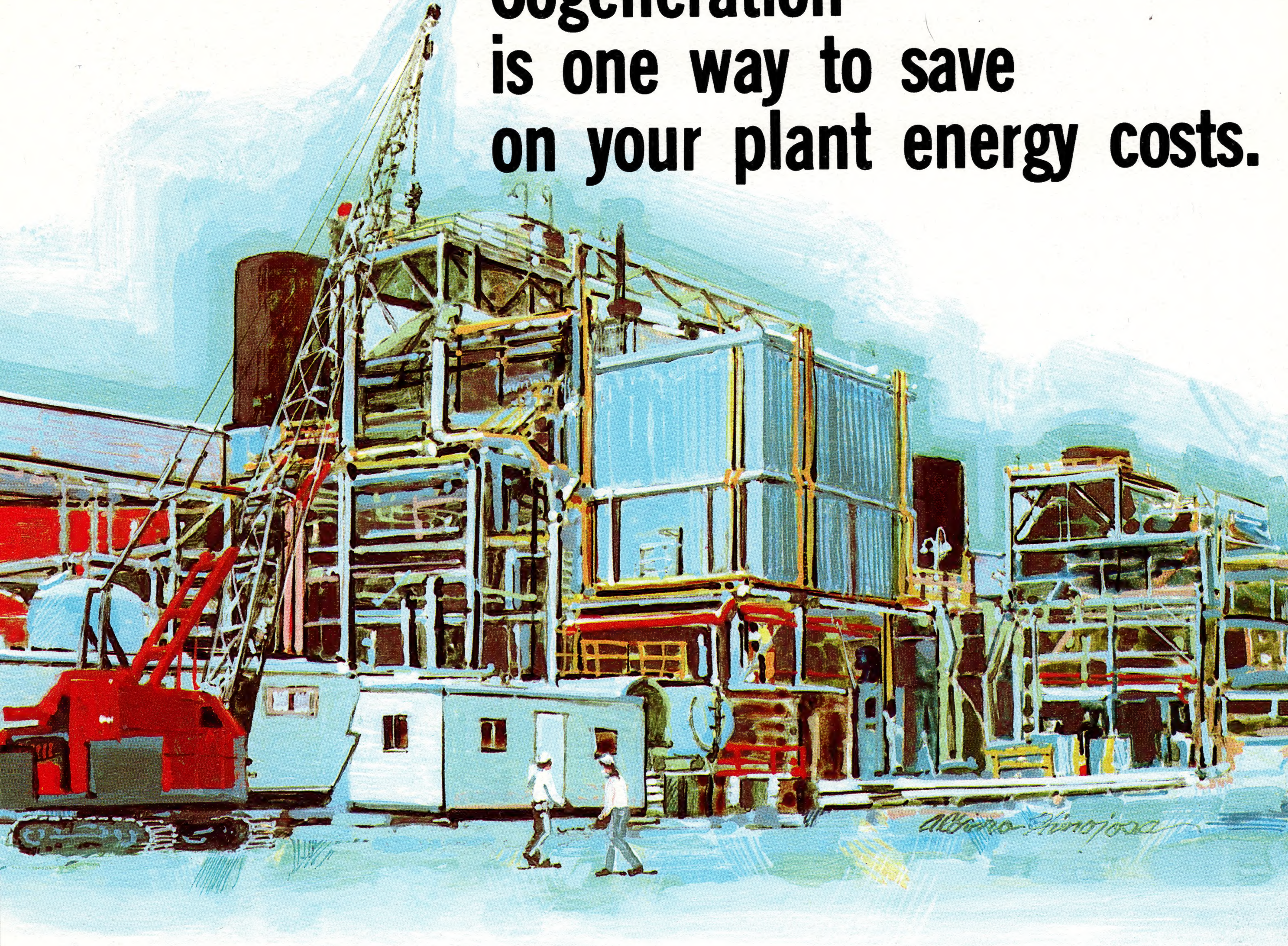

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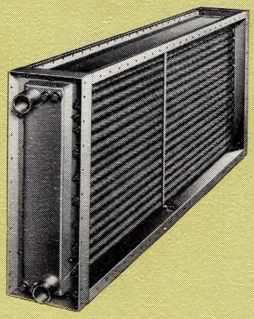
Robert C. Burns Associates, consulting engineers, designed the coil banks, and Ernest O. Menold, Inc. was the mechanical contractor. The Aerofin retrofit payoff: Energy efficiency and improved performance. Put Aerofin energy management to work for you. Ask for Brochure G-77.

PSFS was the first air conditioned major office building on the East coast. It is now on the National Register of Historic Buildings.



Type R
ARI rated chilled water coil, with removable end cover plates for complete draining/easy cleaning of tubes.

AEROFIN CORPORATION
LYNCHBURG, VIRGINIA 24506

Aerofin is sold only by nationally advertised fan manufacturers. Ask for list.

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